Appendix 10

BACT ANALYSIS

APPENDIX 10 - BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

10.1 Introduction

As discussed in Appendix 3, pursuant to the PSD regulations, the proposed Facility is a major stationary source and must utilize best available control technology (BACT) for each pollutant subject to regulation under the Clean Air Act that it would have the potential to emit in significant amounts. PSD defines BACT as:

> "… an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."

This BACT analysis evaluates controls for PC boiler technology and affiliated equipment.[1]

The significant emissions rate for each regulated pollutant was listed in Table 3.3 and is repeated in Table 10.1 below. Table 10.1 compares the potential emissions rate from the Facility to the PSD significant emissions rate for each pollutant regulated under the PSD program. The pollutant is indicated as being subject to BACT if the potential emissions rate exceeds the significant emissions rate.

Pollutants subject to regulation have the potential to be emitted by the Facility from several different sources, or emission units. The emission units include the PC boilers, auxiliary boiler, coal storage/handling system, ash storage/handling system, lime storage/handling system, carbon (mercury sorbent) storage/handling system, emergency diesel engines, fuel storage tanks, and paved and unpaved roads. For purposes of establishing BACT, the various emission units at the proposed Facility have been segregated into several groups. Table 10.2 lists the regulated pollutants that have the potential to be emitted from each group of emission units.

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[1] Nonetheless, WPEA has investigated the current status of Integrated Gasification Combined Cycle (IGCC) and Combustion Fluidized Bed (CFB) technology. Top-down commercial evaluations of IGCC technology and CFB technology are included in Appendices 12 and 13, respectively. In a letter dated December 13, 2005, EPA has stated that it does not believe IGCC should be included in a BACT analysis for a supercritical PC boiler.

Table 10.1 - Potential Emissions of Air Pollutants from Facility

Pollutant	Significant Emission Rate (tons per year)	1,590 MW Facility Potential Emission Rate (tons per year)	Pollutant Subject to PSD BACT ?
Carbon monoxide	100	10,285	Yes
Nitrogen oxides	40	4,814	Yes
Sulfur dioxide	40	6,071	Yes
PM/PM_{10} (filterable)	25/15	2,704/2,687	Yes
Ozone	40 of VOC	248 of VOC	Yes
Lead	0.6	0.79	Yes
Fluorides (as HF)	3	46	Yes
Sulfuric acid mist	7	233	Yes
Total reduced sulfur	10	0	No
Reduced sulfur compounds	10	0	No

Table 10.2 - Emission Units and Applicable Regulated Pollutants

Group	Description Source Designation	Section Reference	Applicable PSD Regulated Pollutants
1	PC Boilers S01, S02, S03	10.5	CO, NO_X, SO_2, PM/PM_{10}, VOC, Pb, F, H_2SO_4
2	Auxiliary Boiler S05	10.6	CO, NO_X, SO_2, PM/PM_{10}, VOC, H_2SO_4
3	Non-combustion PM Sources (Coal, Ash, Carbon, Lime Handling and Paved and Unpaved Roads) S06 through S39	10.7	PM/PM_{10}
4	Emergency Diesel Engines S44 and S45	10.8	CO, NO_X, SO_2, PM/PM_{10}, VOC, H_2SO_4
5	Fuel Storage Tanks S46 through S50	10.9	VOC

10.2 Summary of Top-Down Process

Chapter B of the EPA's Draft New Source Review (NSR) Workshop Manual (EPA's Draft NSR Manual) provides a procedure for use in establishing BACT. This procedure includes a five-step "top-down" process for considering all available control technologies from most stringent to least stringent. The most stringent control technology is considered BACT unless the applicant demonstrates, and the permitting authority agrees, that technical considerations, or energy, environmental or economic impacts justify elimination of the most stringent technology and selection of a less stringent technology.

A summary of each of the five steps in the top-down process is described below. This process was repeated for each of the Facility's emission units and for each regulated pollutant that the emission unit has the potential to emit.

Step 1 - Identify All Control Technologies

The primary objective of Step 1 is to identify all potentially applicable control options. Potentially applicable control options are those air pollution control technologies, or techniques, with a practical potential for application to the emission unit and regulated pollutant under evaluation. Potentially applicable control options are categorized as lower emitting processes/practices or add-on controls.

A lower polluting process/practice is considered applicable if it has been demonstrated in a similar application. An add-on control is considered applicable if it can properly function given the physical and chemical characteristics of the pollutant-bearing emission stream. Combinations of control options should be considered whenever such combinations would provide more effective emissions control.

The range of potentially applicable control options was surveyed. This included control options that have been utilized in other source categories and countries. Technology transfer options were considered to the extent that the technology has been applied to a full-scale operation and is available for purchase. The control technology options identified by lowest achievable emissions rate (LAER) determinations were also included as available technologies.

The following sources of information were utilized to identify potentially applicable control technologies:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) and Control Technology Center
- EPA's National Coal Fired Utility Projects Spreadsheet (March 2006)
- EPA's Clean Air Market Programs website data
- Best Available Control Technology Guideline – South Coast Air Quality Management District
- EPA's New Source Review Technology Transfer Network website
- Federal/State/Local new source review permits, permit applications, and associated inspection/performance test reports

- Control technology vendors
- Technical journals, reports, and newsletters

Based on the guidelines provided in EPA's Draft NSR Manual and summarized above, and utilizing the sources indicated, a comprehensive list of potentially applicable control technology options was developed for each regulated pollutant emitted from each emission unit.

<u>Step 2 - Eliminate Technically Infeasible Options</u>

The objective of Step 2 is to refine the list of potentially applicable control technology options developed in Step 1 by evaluating the technical feasibility of each of the control technology options.

Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on the type of source under review are "demonstrated" and are considered technically feasible.[2] For technologies that have not been demonstrated for a particular source type, EPA's Draft NSR Manual states the following regarding technical feasibility:

> *Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.*[3]

Per this guidance, a technology is considered technically infeasible if it is not available or not applicable. EPA's Draft NSR Manual provides additional guidance on availability and applicability of a given technology for a particular source type:

> *A control technique is considered available… if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review.*[4]
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> *Commercial availability by itself, however, is not necessarily sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to*

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[2] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.
[3] Ibid.
[4] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.

> *the source type under consideration. Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration.*
>
> *In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.*[5]

In the Step 2 analysis, each technology presented in Step 1 is evaluated to determine whether the technology is both available and applicable. Control technologies that are not available or not applicable are determined to be technically infeasible.

<u>Step 3 - Rank Remaining Control Technologies by Control Effectiveness</u>

Step 3 is the ranking of the technically feasible control options developed in Step 2 in order from most effective to least effective in terms of emissions reduction potential.

The ranking of the control options initially involves the establishment of appropriate units of emission performance. Once a measure of performance is established, factors such as the operational characteristics of each of the control technologies and any operating assumptions are considered in establishing emissions reduction potential. For purposes of the BACT demonstrations presented herein, the unit of measure used for the emissions rate of each pollutant from each emission unit was pounds per million British thermal units (lb/MMBtu) for emissions produced by a combustion source.

Achievable emissions limits were established for each of the control technology options based on manufacturer's data, engineering estimates, published literature and the experience of other sources. In cases where the specified emissions reduction level was different than the reduction experienced at other similar sources, source specific, and/or other technical, economic, energy, or environmental factors were presented to justify the difference.

After identifying the appropriate performance units and establishing the emissions performance levels for each control technology, a table was developed to rank the control technology options by their respective emissions performance from lowest to highest emissions level (highest to lowest control effectiveness).

Step 3 of the analysis also includes a listing of the energy, environmental, and economic impacts associated with each control option. These impacts are evaluated in the next step of the analysis.

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[5] Ibid.

Step 4 - Evaluate Most Effective Controls and Document Results

The purpose of Step 4 is to either confirm the suitability of the top ranked control technology option as BACT, or provide clear justification for a determination that a lower-ranked control technology option is BACT for the case under consideration. In order to establish the suitability of a control technology option, a case-by-case evaluation of the energy, environmental, and economic impacts of the control technology is performed.

The energy impacts analysis determines whether the energy requirements of the control technology would result in any significant energy penalties or benefits. The environmental impacts analysis considers site-specific impacts of the solid, liquid, and gaseous discharges that would result from implementation of the control technology. The economic analysis considers the cost effectiveness and the incremental cost effectiveness to establish whether the control technology would result in a negative economic impact.

The case-by-case determinations consider both beneficial and adverse direct impacts from an energy, environmental, and economic standpoint. In cases where the determination establishes that there are significant energy, environmental, and/or economic issues that would preclude the selection of the evaluated alternative as BACT, the basis for this determination is clearly documented, and the next most effective alternative is similarly evaluated. This process continues until the evaluated alternative is not rejected and is selected as BACT.

Step 5 – Most effective control alternative not eliminated selected as BACT

In Step 5, the highest ranked control technology not eliminated in Step 4 is selected as BACT.

10.3 Organization of BACT Analyses

Sections 10.5 through 10.9 of this appendix present the BACT analysis completed for each of the emissions sources listed in Table 10.2. For each source, the five-step procedure is conducted for each of the regulated pollutants applicable to that source.

10.4 BACT Summary

WPEA’s proposed control technology selections and emission limits are listed in Table 10.3. The proposed emission limits comply with all of the applicable NSPS and Nevada State requirements discussed in Appendix 3.

Table 10.3 - Summary of Proposed Emission Limits and Control Technology

Source	Pollutant	Control Technology	Emission Limit (lb/MMBtu)
PC Boilers, S01, S02, and S03	CO	Good combustion practices	0.15, 24-hr rolling avg.
	NO_X	LNB/OFA/SCR	0.07, 24-hr rolling avg.
	SO_2	Dry Scrubber	If fuel Sulfur ≥ 0.45%: 0.09, 24-hr rolling avg. and min. 95% removal, 30-day rolling avg. (1)
			If fuel Sulfur < 0.45%: 0.065, 24-hr average and min. 91% removal, 30-day rolling avg. (1)
	PM/PM_{10} (filterable)	Fabric filter baghouse	0.015, 3-hr avg. 10% opacity, 6-min avg. (2)
	VOC	Good combustion practices	3.6×10^{-3}, 3-hr avg.
	Pb	Fabric filter baghouse	1.8×10^{-5}, 3-hr avg.
	F (as HF)	Dry Scrubber/Fabric Filter Baghouse	9.7×10^{-4}, 3-hr avg.
	H_2SO_4	Dry Scrubber/Fabric Filter Baghouse	3.4×10^{-3}, 3-hr avg. (3)
Auxiliary Boiler, S05	CO	Good combustion practices	0.04, 3-hr avg.
	NO_X	LNB/FGR	0.1, 3-hr avg.
	SO_2	Ultra low sulfur fuel	1.6×10^{-3}, 3-hr avg.
	PM/PM_{10} (total)	Ultra low sulfur fuel	0.05, 3-hr avg.
	PM/PM_{10} (filterable)	Ultra low sulfur fuel	0.01, 3-hr avg.
	VOC	Good combustion practices	0.003, 3-hr avg.
	H_2SO_4	Ultra low sulfur fuel	6.0×10^{-5}, 3-hr avg.

Source	Pollutant	Control Technology	Emission Limit (lb/MMBtu)
Coal, Ash, Carbon, and Lime Mgt Particulate Sources and Roads, S06 to S39	PM/PM_{10}		See Appendix 5
Emergency Diesel Engines, S44 and S45	CO	Combustion Controls	0.75 (generator), 3-hr avg. 0.82 (fire pump), 3-hr avg.
	NO_X	Combustion Controls	1.37 (generator), 3-hr avg. 0.94 (fire pump), 3-hr avg.
	SO_2	Low sulfur fuel	1.6×10^{-3} (generator), 3-hr avg. 1.6×10^{-3} (fire pump), 3-hr avg.
	PM/PM_{10}	Low ash fuel	0.04 (generator), 3-hr avg. 0.05 (fire pump), 3-hr avg.
	VOC	Combustion Controls	0.10 (generator), 3-hr avg. 0.35 (fire pump), 3-hr avg.
	H_2SO_4	Low sulfur fuel	6.0×10^{-5} (generator), 3-hr avg. 6.0×10^{-5} (fire pump), 3-hr avg.
Fuel Storage Tanks, S46 to S50	VOC	Fixed roof tanks with conservation vent valves and best management practices	See Appendix 5

Notes:

(1) Subject to reduction based on demonstrated performance from the first 180 days of operation.

(2) Per the NSPS, compliance with opacity is a 6-minute average except for one 6-minute period per hour of not more than 27% opacity.

(3) The BACT cost analysis and environmental impact comparison reflect the design coal of 0.32% sulfur; however, the proposed emission limit is based on the maximum potential-to-emit.

The following sections present the top-down BACT analysis completed for each of the emissions sources listed in Table 10.2. For each source, the five-step procedure described in Section 10.2 is documented for each regulated pollutant applicable to that source.

10.5 PC Boilers

This section contains the BACT analysis for the pulverized coal-fired boilers for each applicable regulated pollutant identified in Table 10.2.

10.5.1 Carbon Monoxide (CO)

Combustion is a thermal oxidation process in which carbon and hydrogen contained in a fuel combine with oxygen in the combustion zone to form CO_2 and H_2O. CO is generated during the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel. Properly designed and operated boilers typically emit low levels of CO. High levels of CO emissions could result from poor burner design or sub-optimal firing conditions.

Step 1 - Identify All Control Technologies

A listing of potential control technologies is provided below. Per EPA's Draft NSR manual, control options incapable of meeting an applicable New Source Performance Standard (NSPS) would not meet the definition of BACT and are not considered in the BACT analysis.[6]

Lower Emitting Processes/Practices

Lower emitting processes/practices for CO emissions control are combustion control techniques that maximize the thermal oxidation of carbon to minimize the formation of CO. Lower emitting processes/practices include the following:

Combustion Controls

Optimization of the design, operation, and maintenance of the furnace and combustion system is the primary mechanism available for lowering CO emissions. This process is often referred to as combustion controls. The furnace/combustion system design on modern PC-fired boilers provides all of the factors required to facilitate complete combustion. These factors include continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber. As a result, a properly designed furnace/combustion system is effective at limiting CO formation by maintaining the optimum furnace temperature and amount of excess oxygen.

Unfortunately, the addition of excess air and maintenance of high combustion temperatures for control of CO emissions may lead to increased NO_X emissions. Consequently, typical practice is to design the furnace/combustion system (specifically, the air/fuel mixture and furnace temperature) such that CO emissions are reduced as much as possible without causing NO_X levels to significantly increase.

Proper operation and maintenance of the furnace/combustion system helps to minimize the formation and emission of CO by ensuring that the furnace/combustion

[6] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.12.

system operates as designed. This includes maintaining the air/fuel ratio at the specified design point, having the proper air and fuel conditions at the burner, and maintaining the fans and dampers in proper working condition.

Add-On Controls

Add-on controls are post-combustion technologies that operate to reduce the level of CO in the flue gas. Add-on controls include the following:

<u>Flares</u>

Flares are commonly used in the control of organic-laden slipstreams from refineries and other chemical manufacturing processes with sufficient heating value. A flare operates by continuously maintaining a pilot flame that is typically maintained by natural gas. When a combustible exhaust stream is vented to a flare, the exhaust stream is ignited by the pilot flame at the flare tip, and combustion occurs in the ambient air above the flare.

<u>Afterburning</u>

Afterburners convert CO into CO_2 by utilizing simple gas burners to bring the temperature of the exhaust stream up to 1,400 °F to promote complete combustion. Operation of afterburners would require significant amounts of natural gas.

<u>Catalytic Oxidation</u>

A catalytic oxidizer converts the CO in the combustion gases to CO_2 at temperatures ranging from 500 °F to 700 °F in the presence of a catalyst. Catalytic oxidizers are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst. Catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device; however, this would require reheating the exhaust gases to the required operating temperature for the catalytic process.

<u>External Thermal Oxidation (ETO)</u>

ETO promotes thermal oxidation of the CO in the flue gas stream in a location external to the boiler. ETO requires heat (1,400 °F to 1,600 °F) and oxygen to convert CO in the flue gas to CO_2. There are two general types of ETO that are used for the control of CO emissions: regenerative thermal oxidization and recuperative thermal oxidization. The primary difference between regenerative and recuperative ETO is that regenerative ETO utilizes a combustion chamber and ceramic heat exchange canisters that are an integral unit, while recuperative ETO utilizes a separate counterflow heat exchanger to preheat incoming air prior to entering the combustion chamber.

<u>Step 2 – Eliminate Technically Infeasible Options</u>

In this step, the potentially applicable technologies for the control of CO emissions identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR

Manual, control technologies that have been installed and operated successfully on PC-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[7] A technology that has not been demonstrated on PC-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Combustion Controls

Combustion controls, which include furnace and combustion system design and proper boiler operation and maintenance, are proven technologies for the reduction of CO emissions. These technologies have been widely demonstrated in similar applications to generate significantly lower levels of CO emissions when compared to boilers designed, operated and maintained without regard to CO emissions.

Based on the proven success of this control strategy, combustion controls are considered a demonstrated technology for PC-fired boiler CO emissions control. Therefore, combustion controls are considered technically feasible.

Flares

Flares are commonly used in the control of organic slipstreams from refineries and other chemical manufacturing processes with sufficient heating value. Flares have not been demonstrated for PC-fired boiler CO emission control. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

Limitations on the scalability of this technology preclude its commercial availability. For example, the maximum exhaust flow rate for commercially available flares is approximately 1.06 MMscfm,[8] while the flow rate for each PC-fired boiler at the Facility is 1.28 MMscfm (i.e., over 20% higher than commercially available). Therefore, flares are not considered an available control technology for this application. Furthermore, the heating value of the PC-boiler exhaust is essentially zero, far below the practical operating range for flares (i.e., 300 Btu/scf).[9] Since the PC-fired boiler exhaust will not have sufficient heating value for flaring and since flares have not been applied for PC-fired boiler emissions control, flares are not considered an applicable technology for PC-fired boilers.

As discussed in this section, flares are not available or applicable for PC-fired boiler CO emissions control. Therefore, flares are determined to be technically infeasible for PC-fired boilers.

[7] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.
[8] U.S. EPA, document no. EPA-452/F-03-019: *Air Pollution Control Technology Fact Sheet - Flares*, p. 1.
[9] U.S. EPA, document no. EPA-452/F-03-019: *Air Pollution Control Technology Fact Sheet - Flares*, p. 2.

Afterburners

Based on a review of the RBLC database and a survey of air permits for coal-fired power plants, afterburners are not demonstrated for PC-fired boiler CO control. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

The term "afterburner" is generally appropriate only to describe a thermal oxidizer used to control gases coming from a process where combustion is incomplete.[10] Since the PC-fired boilers will be carefully tuned to maximize fuel combustion efficiency (i.e., subsequently minimizing CO emissions) while minimizing NO_X formation, the process will result in essentially complete combustion. Therefore, additional afterburner combustion would not be expected to provide any useful benefit, and afterburners are determined to be not applicable for PC-fired boiler CO emissions control.

Since afterburners are not applicable for PC-fired boiler CO emissions control, afterburners are determined to be technically infeasible.

Catalytic Oxidation

Catalytic oxidizers are typically installed to remove CO, VOC, and organic HAP emissions from exhaust streams in the following equipment/processes:

- Surface coating and printing operations;
- Varnish cookers;
- Foundry core ovens;
- Filter paper processing ovens;
- Plywood veneer dryers;
- Gasoline bulk loading stations;
- Chemical process vents;
- Rubber products and polymer manufacturing; and
- Polyethylene, polystyrene, and polyester resin manufacturing.[11]

In a number of cases, catalytic oxidation has been used to control CO and VOC emissions from natural gas-fired combustion turbines since oxidation catalysts are suitable for gas streams with negligible particulate loading. However, catalytic oxidation is not a demonstrated technology for PC-fired boilers. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

Several factors render CO catalytic oxidation not applicable for PC-fired boilers. First, catalytic oxidation systems require a minimum temperature of 500 °F for proper operation, which would dictate that the catalyst be installed upstream of the flue gas desulfurization and fabric filter systems. The particulate loading of the flue gas stream upstream of the fabric filter would be higher than the design capacity of

[10] U.S. EPA, document no. EPA-452/F-03-022: *Air Pollution Control Technology Fact Sheet - Thermal Incinerator*, p. 1.
[11] U.S. EPA, document no. EPA-452/F-03-018: *Air Pollution Control Technology Fact Sheet - Catalytic Incinerator*, p. 3.

any oxidation catalyst. In addition, trace elements present in coal and the resulting combustion gases (e.g., chlorine and sulfur in particular[12]) would foul an oxidation catalyst and dramatically reduce its effectiveness. Furthermore, SO_2 in the flue gas stream could be oxidized to form SO_3, which could react with the moisture in the flue gas to form sulfuric acid and create a corrosive environment. Alternatively, the SO_3 could convert to NH_4HSO_4 salts that would foul the air preheater. For these reasons, CO catalytic oxidation is not an applicable technology for PC-fired boilers.

Additionally, catalytic oxidation is not an available technology for PC-fired boiler CO emissions control. This technology is not considered commercially available since it has not been demonstrated for PC-fired boilers or similar exhaust streams and since commercially produced package incinerators are not available for exhaust streams with comparable size and composition. For example, typical commercially available package catalytic oxidizers can handle exhaust gas flow rates of up to 0.05 MMscfm,[13] while each PC-fired boiler will have an exhaust flow rate of 1.28 MMscfm, far above the commercially available range for package units. For these reasons, CO catalytic oxidation is not an available technology for PC-fired boilers.

As discussed in this section, catalytic oxidation is not available or applicable for PC-fired boiler CO emissions control. Therefore, catalytic oxidation is determined to be technically infeasible for PC-fired boilers.

<u>External Thermal Oxidation (ETO)</u>

ETO is generally utilized for controlling CO, VOC, or organic HAP emissions from high-concentration, non-combustion sources (e.g., surface coating operations and chemical plants). Regenerative ETO and recuperative ETO have not been demonstrated for use on PC-fired utility plants. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

ETO is not applicable for PC-fired boiler CO control for the same reason as afterburners. Since the PC-fired boilers will be carefully tuned to maximize fuel combustion efficiency (i.e., subsequently minimizing CO emissions) while minimizing NO_X formation, the process will result in essentially complete combustion. Therefore, additional ETO combustion would not be expected to provide any useful benefit (i.e., the PC-fired boiler serves as a thermal oxidizer where high combustion efficiency is a primary concern), and ETO is determined to be not applicable.

Additionally, the regenerative and recuperative ETO heat exchange systems would be vulnerable to the same sulfur concerns as discussed for CO catalytic oxidation above. SO_2 in the flue gas stream could be oxidized to form SO_3, which could react with the moisture in the flue gas to form sulfuric acid and create a corrosive environment. Alternatively, the SO_3 could convert to NH_4HSO_4 salts that would foul the air preheater.

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[12] Ibid.
[13] Ibid.

For the reasons discussed above, ETO is not applicable for PC-fired boiler CO emissions control. Therefore, ETO is determined to be technically infeasible.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, combustion controls are the only remaining feasible control technology. Table 10.4 ranks the feasible CO control technologies by effectiveness when applied to the Facility.

Table 10.4 - Ranking of CO Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu)
Combustion Controls	0.15

Energy Impacts

Combustion controls are an integral part of the combustion process and are designed to maximize combustion efficiency while maintaining optimal CO and NO_X emissions performance. Thus, combustion controls do not create any energy impacts.

Environmental Impacts

Since maximum fuel combustion efficiency (i.e., minimum CO formation) occurs at the high end of the combustion temperature range, there is a potential for increased NO_X emissions due to thermal NO_X formation. Since NO_X formation is a concern, combustion controls are designed and operated to minimize CO and NO_X formation while maximizing combustion efficiency. Thus, combustion controls do not create any significant environmental impacts.

Economic Impacts

Combustion controls are part of the standard design of modern PC-fired boilers and do not create any economic impacts.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of combustion controls are evaluated below.

Energy Impacts

There are no energy impacts that preclude the selection of combustion controls as CO BACT.

Environmental Impacts

As discussed in Step 3, combustion controls are designed to minimize CO emissions while maintaining an appropriate balance with NO_X formation. There are no environmental impacts that preclude the selection of combustion controls as CO BACT.

Economic Impacts

There are no economic impacts that preclude the selection of combustion controls as CO BACT.

Since there are no energy, environmental, or economic impacts that preclude the use of combustion controls, this technology is selected as CO BACT for the PC-fired boilers.

Step 5 – Select BACT

Based on the analysis presented above, BACT for CO emissions control is the application of combustion controls with an emission limit of 0.15 lb/MMBtu. WPEA considers BACT to be compliance on a 30-day rolling average basis; however, WPEA agrees to compliance on a 24-hour rolling average basis.

The RBLC database includes several coal-fired boilers that have CO emissions levels below 0.1 lb/MMBtu. However, all but one of these sources were permitted in the early 1980's, prior to the emergence of the increased sensitivity to control of NO_X. As discussed in Step 1, current practice is to set up combustion controls to compromise between CO and NO_X emissions. Therefore, these sources from the early 1980’s should not be used to establish the BACT emission limit for CO emissions.

The most stringent limits identified (excluding those from the early 1980’s) are listed in Table 10.73. The list includes CO limits in the range of 0.10 to 0.16 lb/MMBtu for PC-fired boilers, with 0.15 being a very common limit.

Ten of the sources with low limits have not been constructed (Desert Rock, Indeck, Thoroughbred, Trimble County, Longview, Prairie State, Comanche, Associated, Big Cajun, and Elm Road). Four other sources, Clover, Cross, Limestone, and Bonanza, have relatively high NO_X limits indicating that the low CO emissions are achieved at the expense of generating higher NO_X. (As previously indicated, this is a consequence of operating the combustion control system to achieve extremely low CO emissions.) Two other sources, Keystone and Chambers, have relatively high NO_X levels after add-on NO_X controls. This suggests that the boiler NO_X emissions are much higher and that the combustion system is designed to minimize CO emissions at the expense of higher NO_X emissions.

Based on this data, no CO emission limits below 0.15 lb/MMBtu have been demonstrated in practice for sources performing at the most stringent NO_X levels. Since increased NO_X levels would be an unacceptable compromise for slightly lower CO levels, WPEA's proposed 0.15 lb/MMBtu is an appropriate CO BACT limit. CO BACT limits of 0.15 lb/MMBtu or higher are reinforced by multiple permits or draft permits issued within the past year (e.g., Two Elk Generation Partners, CPS Spruce Unit 2, Otter Tail Power Company, and KCPL Iatan Station).

Combustion controls will be operated at all times the boilers combust fuel. During periods of startup and shutdown, the boilers may produce higher uncontrolled emissions due to less stable combustion conditions. During startup and shutdown periods, WPEA will utilize combustion controls as BACT with a CO BACT limit of 0.45 lb/MMBtu. Additionally, WPEA will minimize the number of startups that occur each year. Startups are expected to occur approximately 16 times per year per boiler.

10.5.2 Nitrogen Oxides (NO_X)

NO_X is the term used to collectively refer to NO and NO_2. NO_X is formed by the oxidation of nitrogen contained in the fuel (fuel NO_X) and by the combination of elemental nitrogen and oxygen in the high temperature-environment of the combustion zone (thermal NO_X). In coal-fired boilers, fuel NO_X generally accounts for 75% of all NO_X generated. Factors affecting the generation of NO_X include flame temperature, residence time, quantity of excess air, and nitrogen content of the fuel.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below. Per EPA's Draft NSR manual, control options incapable of meeting an applicable NSPS would not meet the definition of BACT and are not considered in the BACT analysis.[14] Control technology combinations that have the potential to meet NSPS levels are addressed in the BACT analysis.

Lower Emitting Processes/Practices

Lower emitting processes/practices for NO_X reduction include the use of fuels with lower nitrogen content and combustion control technologies designed to limit the formation of NO_X by controlling the mixing of air and fuel in the combustion zone. These technologies are generally limited in the amount of reduction possible. The potential lower emitting processes/practices are described in more detail below.

Coal Selection

Nitrogen is one of the elements contained in coal. The amount of nitrogen varies with the type of coal, but generally ranges from 0.5 to 2%.[15] Presumably, fuel NO_X emissions could be reduced by burning a coal that contains less nitrogen.

Low NO_X Burners (LNB)

LNB are designed to limit NO_X formation by controlling the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air, resulting in one or more of the following conditions: (a) reduced oxygen in the primary flame zone; (b) reduced flame temperature; or (c) reduced residence time at peak temperature.

Overfire Air (OFA)

OFA, also referred to as air staging, is a combustion control technology in which 5% to 20% of the total combustion air is diverted from the burners and injected through

[14] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.12.
[15] U.S. EPA, *Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report, Chapter 3, Criteria Air Pollutant Emission Controls for Coal-fired Electric Utility Boilers,* EPA Document No. 600/R-01-109, April 2002.

ports located above the top burner level.[16] OFA is generally used in conjunction with operating the burners at stoichiometric or slightly sub-stoichiometric conditions, which reduces NO_X formation. The OFA is then added to achieve complete combustion. OFA can be used in conjunction with LNB. The combination of LNB and OFA is compatible with other add-on NO_X control technologies.

Rotating Opposed Fire Air (ROFA®)

ROFA® is a new combustion technology developed by Mobotec USA, Inc. The ROFA® design injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. ROFA® has only been utilized as a retrofit technology.

Induced Flue Gas Recirculation (IFGR)

Induced flue gas recirculation (IFGR) recirculates boiler flue gas from the boiler outlet to the furnace where it is reintroduced into the combustion process. Fuel/air mixing in the combustion region is intensified by the recirculated flue gas when introduced into the flame during the early stages of combustion. This intensified mixing offsets the decrease in flame temperature and results in NO_X levels that are lower than those achieved without IFGR. The level of NO_X reduction depends on the burner and furnace design. An additional benefit of IFGR is the potential to lower CO emissions.

Add-On Controls

Add-on controls for NO_X reduction are post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of NO_X after the combustion process is complete. Potential add-on controls include the following:

Selective Catalytic Reduction (SCR)

SCR is a post-combustion NO_X reduction technology in which ammonia is added to the flue gas upstream of a catalyst bed. The ammonia and NO_X react on the surface of the catalyst, forming N_2 and water. SCR reactions occur in a temperature range of 650 °F to 750 °F.[17] Typical catalyst material is titanium dioxide, tungsten trioxide, or vanadium pentoxide.

Natural Gas Reburning (NGR) + Selective Catalytic Reduction (SCR)

Although typically used in retrofit applications only, NGR could presumptively be used in conjunction with SCR on a new unit.

[16] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1370.
[17] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1374.

NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, thus creating a secondary combustion zone called the reburn zone. In NGR, the secondary (or reburn) fuel, natural gas, is injected to produce a slightly fuel rich reburn zone. Overfire air is added above the reburn zone to complete burnout of the reburn fuel. As flue gas passes through the reburn zone, part of the NO_X formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) and converted to molecular nitrogen (N_2). NGR has been reported to achieve NO_X reductions down to 0.16 lb/MMBtu.[18]

Fuel-Lean Gas Reburning (FLGR) + Selective Catalytic Reduction (SCR)

Although typically used in retrofit applications only, FLGR could presumptively be used in conjunction with SCR on a new unit.

FLGR, also known as controlled gas injection, is a process in which careful injection and controlled mixing of natural gas into the furnace exit region reduces NO_X. The gas is normally injected into a lower temperature zone than in NGR. Whereas NGR requires 15% to 20% of furnace heat input from gas and requires burnout air, the FLGR technology achieves NO_X control using less than 10% gas heat input and no burnout air.[19] Less NO_X reduction is achieved with FLGR when compared with NGR. FLGR has been reported to achieve NO_X reductions down to 0.27 lb/MMBtu.[20]

Advanced Gas Reburning (AGR) + Selective Catalytic Reduction (SCR)

Although typically used in retrofit applications only, AGR could presumptively be used in conjunction with SCR on a new unit.

AGR adds a nitrogen rich compound (typically urea or ammonia) downstream of the reburning zone. The reburning system is adjusted for somewhat lower NO_X reduction to produce free radicals that enhance the selective non-catalytic NO_X reduction. AGR systems can be designed in two ways: (1) non-synergistic, which is essentially the sequential application of NGR and selective non-catalytic reduction (i.e., the nitrogen agent is injected downstream of the burnout air); and (2) synergistic, in which the nitrogen agent is injected with a second burnout air stream. To obtain maximum NO_X reduction and minimum reagent slip in non-synergistic systems, the nitrogen agent must be injected so that it is available for reaction with the furnace gases within a temperature zone around 1,800 °F.[21] AGR has been reported to achieve NO_X reductions down to 0.12 lb/MMBtu.[22]

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[18] Folsom, Blair A., Tyson, Thomas J., *Combustion Modification – An Economic Alternative for Boiler NOx Control,* GE Power Systems, April 2001.
[19] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1378.
[20] Northeast States for Coordinated Air Use Management (NESCAUM), Status Report on NO_X: Control Technologies and Cost Effectiveness for Utility Boilers, June 1998.
[21] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1378.
[22] Folsom, B.A., Tyson, T.J., *Combustion Modification – An Economic Alternative for Boiler NOx Control,* GE Power Systems, April 2001, p. 7.

Amine Enhanced Gas Injection (AEGI) + Selective Catalytic Reduction (SCR)

Although typically used in retrofit applications only, AEGI could presumptively be used in conjunction with SCR on a new unit.

AEGI is similar to AGR, except that burn out air is not used, and the selective non-catalytic reduction reagent and reburn fuel are injected to create local, fuel-rich NO_x reduction zones in an overall fuel-lean furnace. The fuel-rich zone exists in local eddies, as in FLGR, with the overall furnace in an oxidizing condition; however the reduction reagent participates with natural gas (or other hydrocarbon fuel) in a NO_x reduction reaction. AEGI has been shown to reduce uncontrolled NO_X emissions by 50% to 70%.[23]

Hybrid Selective Reduction (HSR)

HSR is a combination of selective non-catalytic reduction (SNCR) and SCR that is designed to provide the performance of full SCR with a smaller footprint and potentially lower costs. In HSR, an SNCR system is used to achieve some NO_X reduction and to produce a controlled amount of ammonia slip that is used in a downstream in-duct SCR reactor for additional NO_X reduction. Since HSR involves the sequential application of SNCR and SCR, the final emission level of an HSR system is equivalent to the level of control achieved by an SCR system.

SCONOx

SCONOx is a catalyst technology developed by Goal Line Environmental Technologies. The technology uses a precious metal catalyst to simultaneously convert NO_X and CO to CO_2, H_2O, and N_2. The catalyst must be periodically removed from service for regeneration. This requirement necessitates multiple catalyst sections and additional ductwork and dampers for isolation. Hydrogen diluted with steam is used to regenerate the catalyst and produce a stream of H_2O and N_2 that is vented to the stack.

THERMALONOx

The THERMALONOx technology has been developed by Thermal Engineering International as an option for the control of NO_X emissions. The technology is based on the oxidation of NO to NO_2 and then dissolving the NO_2 in water. The THERMALONOx technology is intended for use with a wet flue gas desulfurization (FGD) system used for SO_2 emission control. The NO oxidation is accomplished by injecting elemental phosphorous into the flue gas stream in a gas reactor installed upstream of the wet FGD absorber. The NO_2 becomes dissolved in the wet FGD absorber and can be removed as elemental N_2 or various phosphate compounds that may be used as fertilizer and/or animal food additives.

[23] Hall, R.E. and Srivastava, R.K., *An EPA Perspective on Reburn Technology for NO_X Control,* Presented at the 2004 Conference on Reburning for NO_X Control.

Electro-Catalytic Oxidation (ECO)

ECO is a multi-pollutant control technology under development by Powerspan Corporation. According to the company's website,[24] ECO is a multi-pollutant control technology that simultaneously controls SO_2, NO_X, Hg, and $PM_{2.5}$. The ECO process is located downstream of a plant's primary particulate removal device (electrostatic precipitator or fabric filter). The process includes a reactor that oxidizes the gaseous pollutants; a scrubber that removes NO_X, SO_2, and the oxidizer reactor products; and a wet electrostatic precipitator that captures the oxidized pollutants.

In 2005, the ECO technology completed a 180-day pilot testing run at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio. The pilot unit processed a flue gas slipstream that represented approximately one-third of the exhaust flow from a 156-MW front wall-fired boiler combusting coal.[25]

Pahlman Process

The Pahlman Process is a multi-pollutant control technology that simultaneously controls NO_X and SO_2. EnviroScrub Technologies, the developer of the Pahlman Process, has released only general information about the technology. According to the company's website, the process is located downstream of the particulate control device and utilizes a spray dryer absorber where a proprietary Pahlmanite™ scrubber material contacts the exhaust stream. The exhaust stream then passes through a "baghouse reaction chamber" where the Pahlmanite™ material is removed prior to the final exhaust stack. This technology is currently in the pilot stage of development, and the company operates a trailer-mounted pilot demonstration unit that can process coal-fired boiler exhaust slip streams of up to 2,000 scfm.[26]

The following are not considered as potential stand-alone BACT control technologies since they would not be able to achieve the NSPS Subpart Da NO_X emission limit of 1.0 lb/MWh[27] (0.11 lb/MMBtu for the WPEA coal-fired boilers).[28]

- Natural Gas Reburning (NGR)
- Fuel Lean Gas Reburning (FLGR)
- Advanced Gas Reburning (AGR)
- Amine Enhanced Gas Injection (AEGI)
- Selective Non-Catalytic Reduction (SNCR)

[24] http://www.powerspan.com/technology/scrubber_overview.shtml.
[25] http://www.powerspan.com/technology/scrubber_demonstration.shtml.
[26] http://www.enviroscrub.com/pilot.asp, April 27, 2006.
[27] 40 CFR §60.44Da(e)(1).
[28] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.12.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable technologies for the control of NO_X emissions identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on PC-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[29] A technology that has not been demonstrated on PC-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Coal Selection

The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value, each of which strongly affects the design and cost of the boiler and air pollution control equipment. While lower-nitrogen or higher-volatile fuels can result in lower NO_X formation, coal is not sorted by nitrogen content or NO_X production potential. Therefore, coal selection is not an available control option, and coal selection is determined to be technically infeasible.

(Although WPEA is not proposing firing primarily PRB coal specifically to reduce NO_X emissions, NO_X emissions from PRB coal combustion have been shown to be 20% to 40% less than emissions from bituminous coals.[30] This is likely due to the higher volatility of PRB coals. The volatile portion carries a significant amount of the fuel nitrogen. Under staged combustion, the volatiles are released early in the combustion process and are burned in the overfire air zone where there is a lower potential to form fuel NO_X.[31])

Low NO_X Burners (LNB)

LNB are a mature technology for the reduction of NO_X formation during combustion. LNB have been demonstrated in practice and are available from numerous vendors that are willing to offer performance guarantees. LNB are considered standard equipment for modern boilers and are expected to be furnished with a new boiler regardless of other post-combustion NO_X emission reduction technologies employed. For these reasons, LNB are considered technically feasible.

Overfire Air (OFA)

OFA is a mature technology most often utilized concurrently with the application of LNB. OFA compliments the stoichiometric to sub-stoichiometric operation of LNB by providing the air required to complete fuel combustion and limit the formation of CO and VOC. OFA is expected to be furnished with a new boiler regardless of other

[29] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.
[30] Ozone Transport Assessment Group (OTAG), OTAG Technical Supporting Document Chapter 5 - Appendix A, States' Report on Electric Utility Nitrogen Oxides Reduction Nitrogen Oxides Reduction Technology Options for Application, April 11, 1996.
[31] Kokkinos, et al., *Comparison of NOx Emissions Reductions with PRB and Bituminous Coals on Tangentially-Fired Boilers,* The Babcock & Wilcox Company, Presented at Power-Gen International 2002.

post-combustion NO_X emission reduction technologies employed. For these reasons, OFA is considered technically feasible.

LNB and OFA have become a standard component of all new utility boiler designs. For this reason, the NO_X emissions levels achieved through the implementation of LNB and OFA are considered the baseline emissions level, and all other technically feasible control technologies were considered in combination with LNB and OFA.

Rotating Opposed Fire Air (ROFA®)

To date, ROFA® has only been installed as a retrofit technology on units firing bituminous coals. As discussed above, in order to implement ROFA®, WPEA would be expected to encounter time delays and resource penalties in developing this technology for subbituminous (PRB) coal combustion. Per EPA's Draft NSR Manual, technologies that would present these problems are not considered available:

> *"A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique.*[32]

Accordingly, ROFA® is not considered available. Thus, this technology is determined to be technically infeasible for PRB coal combustion.

Based on data published by the manufacturer, ROFA® has been applied as a retrofit technology for units combusting eastern bituminous coal. For eastern bituminous coal, the ROFA® technology has been reported as achieving NO_X emission rates of 0.22 lb/MMBtu to 0.295 lb/MMBtu for full load and 50% load, respectively (emissions below 50% load were not reported).[33] However, these emission rates are not below the range of emissions reported for LNB + OFA (e.g., as low as 0.25 lb/MMBtu for bituminous coal[34]). Since the ROFA® technology would not be expected to provide better emissions performance than the LNB + OFA baseline, ROFA® technology is not considered further in this analysis.

Induced Flue Gas Recirculation (IFGR)

IFGR has been demonstrated as a NO_X reduction technology on smaller scale natural gas and oil-fired boilers. However, this technology has not been commercially developed for PC-fired boilers. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

Based on a review of the RBLC database and available vendor information, IFGR is only commercially available for gas and oil-fired units. Since technical issues preclude the direct transfer of this technology to PC-fired boilers, IFGR is considered not available.

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[32] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.
[33] Coombs, et al., *SCR Levels of NO_X Reduction with ROFA and Rotamix (SNCR) at Dynegy's Vermilion Power Station*, presented at the 2004 Stack Emissions Symposium, July 28-30, 2004.
[34] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1370.

Additionally, the applicability of this technology is precluded due to the technical complications associated with recirculating the volume of hot, ash-laden flue gas that is generated by a large coal-fired boiler. The primary complication is the significant operations and maintenance issues that would result.

In March 2005, the Electric Power Research Institute (EPRI) published a paper describing part of the first phase of a project to study the applicability of induced flue gas recirculation (IFGR) to coal-fired utility boilers.[35] The paper documents a computational fluid dynamics (CFD) model that was developed to predict the effectiveness of IFGR for a unit at an American Electric Power facility. The study was a mathematical modeling exercise only; no IFGR system was physically installed. The results of the CFD modeling predicted moderate NO_X reductions, although EPRI stated that application of IFGR to coal-fired power plants as a NO_X reduction technology has not been proven in practice and that IFGR may only be applicable to boilers that use specific types of coal or that are of a particular design. Based on this information, IFGR is considered not applicable for PC-fired boiler NO_X control.

As discussed above, IFGR is not available or applicable for PC-fired boiler NO_X emissions control.

Selective Catalytic Reduction (SCR)

SCR is a proven technology for the reduction of NO_X emissions. It has been demonstrated in similar applications to reduce NO_X emissions significantly over a range of load conditions. SCR has been applied on coal-fired boilers from 100 MW up to 1,300 MW. For this reason, SCR is considered technically feasible.

Natural Gas Reburning (NGR) + Selective Catalytic Reduction (SCR)

NGR could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease due to lower inlet NO_X concentrations, and there is no data available to indicate that the NGR + SCR combination could achieve a lower NO_X emission rate than SCR alone. Also, installing NGR would represent additional capital and operating costs with no assurance of improved environmental performance.[36]

Regarding the evaluation of multiple control technologies that achieve an equivalent level of performance, EPA's Draft NSR Manual allows applicants to review only the lowest-cost option if several potential options achieve an essentially identical level of performance.[37] As documented above, NGR in conjunction with SCR would be expected to achieve essentially identical environmental performance as SCR alone.

[35] EPRI, abstract from *Numerical Simulation of Induced Flue Gas Recirculation (IFGR) Operation at American Electric Power's Plant Welsh Unit 1*, March 2005.
[36] Cost information is provided to establish the higher cost of this technology – Since natural gas is not currently available at the site, WPEA would have to construct approximately 90 miles of natural gas pipeline at an estimated capital cost of $73.7 million. Annual costs for natural gas are estimated at $104.9 million.
[37] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.20.

Additionally, utilizing an NGR system in conjunction with SCR would represent a higher cost than utilizing SCR alone (i.e., capital cost for natural gas pipeline and operating costs for purchasing natural gas). Therefore, in accordance with EPA guidance, WPEA will evaluate only the less costly option that achieves equivalent performance (i.e., WPEA will only carry SCR forward in the analysis, as opposed to NGR + SCR).

This BACT methodology was allowed by the Nebraska Department of Environmental Quality (NDEQ) with no adverse comments from EPA during permitting of the Whelan Energy Center in March 2004.[38]

Fuel Lean Gas Reburning (FLGR) + Selective Catalytic Reduction (SCR)

FLGR could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease due to lower inlet NO_X concentrations, and there is no data available to indicate that the FLGR + SCR combination could achieve a lower NO_X emission rate than SCR alone. Also, installing FLGR would represent additional capital and operating costs with no assurance of improved environmental performance.[39]

Regarding the evaluation of multiple control technologies that achieve an equivalent level of performance, EPA's Draft NSR Manual allows applicants to review only the lowest-cost option if several potential options achieve an essentially identical level of performance.[40] As documented above, FLGR in conjunction with SCR would be expected to achieve essentially identical environmental performance as SCR alone. Additionally, utilizing an FLGR system in conjunction with SCR would represent a higher cost than utilizing SCR alone (i.e., capital cost for natural gas pipeline and operating costs for purchasing natural gas). Therefore, in accordance with EPA guidance, WPEA will evaluate only the less costly option that achieves equivalent performance (i.e., WPEA will only carry SCR forward in the analysis, as opposed to FLGR + SCR).

This BACT methodology was allowed by the NDEQ with no adverse comments from EPA during permitting of the Whelan Energy Center in March 2004.[41]

Advanced Gas Reburning (AGR) + Selective Catalytic Reduction (SCR)

AGR could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease due to lower inlet NO_X concentrations, and there is no data available to indicate that the AGR + SCR combination could achieve a lower NO_X emission rate than SCR alone. Also, installing AGR would represent additional capital and operating costs with no assurance of improved environmental performance.

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[38] NDEQ Construction Permit Fact Sheet, Whelan Energy Center, March 2004.
[39] Cost information is provided to establish the higher cost of this technology – Since natural gas is not currently available at the site, WPEA would have to construct approximately 90 miles of natural gas pipeline at an estimated capital cost of $63.0 million. Annual costs for natural gas are estimated at $48.9 million.
[40] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.20.
[41] NDEQ Construction Permit Fact Sheet, Whelan Energy Center, March 2004.

Regarding the evaluation of multiple control technologies that achieve an equivalent level of performance, EPA's Draft NSR Manual allows applicants to review only the lowest-cost option if several potential options achieve an essentially identical level of performance.[42] As documented above, AGR in conjunction with SCR would be expected to achieve essentially identical environmental performance as SCR alone. Additionally, utilizing an AGR system in conjunction with SCR would represent a higher cost than utilizing SCR alone (i.e., capital cost for AGR components and operating costs such as AGR reagent). Therefore, in accordance with EPA guidance, WPEA will evaluate only the less costly option that achieves equivalent performance (i.e., WPEA will only carry SCR forward in the analysis, as opposed to AGR + SCR).

This BACT methodology was allowed by the NDEQ with no adverse comments from EPA during permitting of the Whelan Energy Center in March 2004.[43]

<u>Amine Enhanced Gas Injection (AEGI) + Selective Catalytic Reduction (SCR)</u>

AEGI could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease due to lower inlet NO_X concentrations, and there is no data available to indicate that the AEGI + SCR combination could achieve a lower NO_X emission rate than SCR alone. Also, installing AEGI would represent additional capital and operating costs with no assurance of improved environmental performance.

Regarding the evaluation of multiple control technologies that achieve an equivalent level of performance, EPA's Draft NSR Manual allows applicants to review only the lowest-cost option if several potential options achieve an essentially identical level of performance.[44] As documented above, AEGI in conjunction with SCR would be expected to achieve essentially identical environmental performance as SCR alone. Additionally, utilizing an AEGI system in conjunction with SCR would represent a higher cost than utilizing SCR alone (i.e., capital cost for AEGI components and operating costs such as AEGI reagent). Therefore, in accordance with EPA guidance, WPEA will evaluate only the less costly option that achieves equivalent performance (i.e., WPEA will only carry SCR forward in the analysis, as opposed to AEGI + SCR).

This BACT methodology was allowed by the NDEQ with no adverse comments from EPA during permitting of the Whelan Energy Center in March 2004.[45]

<u>Hybrid Selective Reduction (HSR)</u>

HSR has been implemented primarily as a retrofit technology. This technology has been demonstrated to reduce NO_X emissions equivalent to SCR on a 320 MW coal-fired boiler.

[42] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.20.
[43] NDEQ Construction Permit Fact Sheet, Whelan Energy Center, March 2004.
[44] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.20.
[45] NDEQ Construction Permit Fact Sheet, Whelan Energy Center, March 2004.

Regarding the evaluation of multiple control technologies that achieve an equivalent level of performance, EPA's Draft NSR Manual states the following:

> *A possible outcome of the top-down BACT procedures discussed in this document is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not EPA's intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. Consequently, judgment should be used in deciding what alternatives will be evaluated in detail….*[46]

As discussed in Step 1, since HSR involves the sequential application of SNCR and SCR, the final emission level of an HSR system is equivalent to the level of control achieved by an SCR system. Although HSR and SCR have both been demonstrated in practice, stand-alone SCR has been demonstrated as effective in many more installations. Based on the proven reliability and effectiveness of stand-alone SCR, WPEA will evaluate only more established option that achieves equivalent performance (i.e., WPEA will only carry stand-alone SCR forward in the analysis, as opposed to HSR). WPEA is willing to accept the potentially higher cost of SCR in exchange for the demonstrated reliability of this proven technology.

<u>SCONOx</u>

SCONOx is not a demonstrated technology for controlling NO_X emissions from coal-fired boilers. Therefore, an assessment of the availability and applicability is conducted to determine if the technology is technically feasible.

SCONOx technology has not been demonstrated on flue gas generated by coal combustion. It has only been demonstrated on gas-fired combined cycle power plants. The manufacturer of this technology does not offer SCONOx for application to coal-fired boilers. Therefore, SCONOx is considered not available.

Additionally, the presence of sulfur in the flue gas has the potential to poison the SCONOx catalyst, limiting its effectiveness and its useful life. Furthermore, the particulate loading in the exhaust stream would foul the catalyst, rendering it ineffective. Therefore, SCONOx is not applicable for coal-fired boiler NO_X control.

Since this technology is not available and not applicable for coal-fired boiler NO_X control, SCONOx is determined to be technically infeasible.

<u>THERMALONOx</u>

THERMALONOx technology has been installed and tested on flue gas from a coal-fired boiler. The goal of the test was to demonstrate a NO_X reduction of 75%. The poorer-than-expected results of this first commercial operation prompted the host utility to halt testing of the technology until further laboratory testing could be completed. Thus, THERMALNOx is not a demonstrated technology for controlling NO_X emissions from coal-fired boilers, and an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

[46] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.20.

Per EPA's Draft NSR Manual, a technology must reach the commercial sales stage to be considered available.[47] As discussed above, THERMALNOx is currently in the laboratory/pilot stage of development. Since THERMALNOx has not achieved the commercial sales stage of development, this technology is considered not available. Thus, THERMALNOx is determined to be technically infeasible.

Electro-Catalytic Oxidation (ECO)

The ECO technology is still in the pilot plant stage of development. To date, the only application of this technology has been a pilot facility processing a flue gas slip stream from a coal-fired boiler.[48] This technology has not been demonstrated for full-scale operations. EPA's Draft NSR Manual states the following regarding technologies in the pilot stage of development:

> *"…technologies in the pilot scale testing stages of development would not be considered available for BACT review."*[49]

Since the ECO technology has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available. Therefore, the ECO technology is determined to be technically infeasible.

Pahlman Process

The Pahlman Process has been demonstrated in small scale testing to reduce NO_X emissions from coal-fired boiler exhaust slip streams. However, the trailer mounted demonstration system is currently capable of treating up to 2,000 scfm of flue gas.[50] Based on this information, the Pahlman Process is still in the pilot stage of development.

Since the Pahlman Process has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available. Therefore, the Pahlman Process is determined to be technically infeasible.

In summary, following NO_X emission control technologies are carried forward to Step 3 of the BACT analysis:

- Low NO_X Burners + Overfire Air (LNB + OFA)
- Selective Catalytic Reduction (SCR)

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

[47] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.
[48] http://www.powerspan.com/technology/scrubber_demonstration.shtml.
[49] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.
[50] http://www.enviroscrub.com/pilot.asp, April 27, 2006.

As discussed previously, LNB + OFA is compatible with the add-on NO_X control technologies and is presented in conjunction with each add-on technology as appropriate.

Ranking by Control Effectiveness

Following elimination of the equivalent and technically infeasible control technologies in Step 2, SCR is the only remaining add-on control technology. Table 10.5 ranks the feasible NO_X control technologies by effectiveness when applied to the Facility.

Table 10.5 - Ranking of NO_X Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu)
LNB + OFA + SCR	0.06 to 0.09 (1)

Notes:
(1) Control effectiveness on a 24-hour rolling average basis.

The control effectiveness range presented in Table 10.5 was established based on available industry research and EPA's RBLC database. The lower value (0.06 lb/MMBtu) is based on the recent EPA Region 9 permit for the Desert Rock Energy Center. The upper value (0.09 lb/MMBtu) is consistent with recent BACT determinations in Arkansas and Wyoming and is below the NSPS Da NO_X limit of 1.0 lb/MWh[51] (0.11 lb/MMBtu for the WPEA coal-fired boilers).

Energy Impacts

LNB + OFA is a standard element of the combustion process and does not create any energy impacts.

The SCR technology will require additional auxiliary power to overcome the draft loss across the catalyst, to supply hot dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Environmental Impacts

Properly tuned LNB + OFA systems do not create adverse impacts. As discussed in the CO BACT analysis, combustion controls are designed and operated to achieve the optimum balance between CO and NO_X emissions.

SCR requires the storage and use of ammonia, which can cause environmental consequences if not handled and stored properly. Ammonia for the SCR can be in either liquid form or created from solid urea. If liquid ammonia is used, storage of this substance may trigger requirements as specified by the Occupational Safety and Health Administration and the Community Right-to-Know Act. Ammonia slip (i.e.,

[51] 40 CFR §60.44Da(e)(1).

unreacted ammonia emitted from the stack) is typically 5 ppm or less[52] but has the potential to increase with increasing ammonia feed rates.

Additionally, during the life of the Facility, the catalyst would require periodic replacement. The SCR catalyst is fabricated from various metals that might need to be disposed of as a hazardous waste. The used catalyst would be returned to the catalyst supplier for regeneration or would be disposed of in an environmentally responsible manner.

Another possible impact of SCR is that the SCR catalyst oxidizes a portion of the SO_2 in the flue gas to SO_3. The formation of SO_3 is problematic in that it may react with moisture in the flue gas to form H_2SO_4. The oxidation of SO_2 may be minimized by specification of the catalyst material, but this might result in lower NO_X reduction capability.

<u>Economic Impacts</u>

OFA + LNB is part of the standard design of modern PC-fired boilers and does not create any economic impacts.

The cost of control using SCR has been presented as $2,000 to $5,000 per ton of NO_X removed.[53]

Step 4 - Evaluate Most Effective Controls and Document Results

Step 3 of the BACT evaluation established that SCR in combination with LNB and OFA offers the highest level of NO_X control. Step 4 evaluates the energy, environmental and economic impacts of this control technology.

<u>Energy Impacts</u>

The energy impacts discussed in Step 3 are not significant enough to preclude the use of the SCR in combination with LNB and OFA as BACT for NO_X.

<u>Environmental Impacts</u>

The environmental impacts discussed in Step 3 are not significant enough to preclude the use of the SCR in combination with LNB and OFA as BACT for NO_X.

<u>Economic Impacts</u>

While there are significant capital costs and operating costs associated with SCR, WPEA is willing to accept these costs due to the high effectiveness and reliability of this technology. The economic impacts are not significant enough to preclude the use of the SCR in combination with LNB and OFA as BACT for NO_X.

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[52] EPA Office of Air and Radiation, *Performance of Selective Catalytic Reduction on Coal-Fired Steam Generating Units*, June 25, 1997.

[53] U.S. EPA, document no. EPA-452/F-03-019: *Air Pollution Control Technology Fact Sheet – Selective Catalytic Reduction (SCR)*, p. 2.

Step 5 - Select BACT

Based on the analysis presented above, BACT for NO_X is considered to be the application of SCR in combination with LNB and OFA with a limit of 0.07 lb/MMBtu on a 24-hour rolling average basis.

A list of the NO_X emission limits for the most stringently controlled PC-fired boilers found is presented at the end of this Appendix in Table 10.74. This list includes permit limits from EPA's RBLC database and EPA's March 2006 National Coal Database Spreadsheet. WPEA's proposed BACT limit is consistent with the most stringent entries in the RBLC database and the National Coal Database Spreadsheet. Table 10.6 discusses all such facilities with BACT limits less than 0.07 lb/MMBtu.

Table 10.6 – Discussion of NO_X BACT Limits for PC-Fired Boiler Facilities Permitted at Less than 0.07 lb/MMBtu

Facility	State	Emission Limit (lb/MMBtu)	Notes
Desert Rock Energy Center	NM	0.06 (24-hour average)	Limit has not been demonstrated in practice.
Newmont Mining	NV	0.067 (24-hour average)	Limit has not been demonstrated in practice.
City Public Service, Spruce Unit 2	TX	0.07 (30-day rolling average) (1)	Limits have not been demonstrated in practice. Draft permit includes a 12-month optimization study for SCR operation during which the annual limit is waived. This facility's BACT emission limit of 0.07 lb/MMBtu on a 30-day average is less stringent than WPEA's proposed limit of 0.07 lb/MMBtu on a 24-hour average.
Sandy Creek Energy Station	TX	0.07 (30-day rolling average) (1)	Limits have not been demonstrated in practice. Draft permit includes a 12-month optimization study for SCR operation during which the annual limit is waived. This facility's BACT emission limit of 0.07 lb/MMBtu on a 30-day average is less stringent than WPEA's proposed limit of 0.07 lb/MMBtu on a 24-hour average.
Weston 4	WI	0.07 (30-day rolling average) (1)	Limits have not been demonstrated in practice. This facility's BACT emission limit of 0.07 lb/MMBtu on a 30-day average is less stringent than WPEA's proposed limit of 0.07 lb/MMBtu on a 24-hour average.

Notes:

(1) In addition to the 30-day rolling average limits shown, these units also have NO_X limits on a rolling 12-month averaging period of 0.05 lb/MMBtu for the Texas facilities and 0.06 lb/MMBtu for the Wisconsin facility. Since WPEA is proposing a stringent 24-hour average BACT limit, the table above only shows emission limits with short-term averaging periods for comparison.

As documented in the table above, WPEA's proposed NO_X BACT limit of 0.07 lb/MMBtu (24-hour average) is consistent with the lowest NO_X BACT limits that have been permitted.

While Newmont's limit is slightly lower at 0.067 lb/MMBtu, the difference between these limits is not significant. Regarding the 0.06 lb/MMBtu permitted for Desert Rock, this facility has not been constructed, and the NO_X BACT limit has not been demonstrated in practice. While previous permit decisions can provide guidance for future BACT determinations, permitting agencies must establish BACT on a case-by-case and facility-by-facility basis. EPA's Draft NSR Manual states the following regarding the basis for BACT limits:

> *Manufacturer's data, engineering estimates and the experience of other sources provide the basis for determining achievable limits. Consequently, in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative.*[54]

While WPEA's proposed NO_X BACT limit of 0.07 lb/MMBtu would not be the lowest BACT limit ever permitted, 0.07 lb/MMBtu represents the maximum degree of reduction for NO_X at the WPEA PC-fired boilers, taking into account energy, environmental, and economic impacts. The proposed NO_X BACT limit takes into account WPEA's facility-specific boiler size, boiler design, fuel options, and emission controls. The Desert Rock facility will utilize a different design, a different capacity, and a different fuel (coal from the Navajo mine). Since the WPEA Facility is unique in its design, it would be unreasonable to require WPEA to meet a NO_X BACT limit of 0.06 lb/MMBtu simply because this limit has been permitted for another facility. The U.S. EPA Environmental Appeals Board recently stated agreement with this position:

> *…PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but that those limits must also reflect consideration of any practical difficulties associated with using the control technology.*[55]

WPEA's proposed NO_X BACT limit of 0.07 lb/MMBtu is based on careful engineering evaluation, vendor consultation, and consideration of the energy, environmental, and economic impacts as documented above for this unique facility. Thus, WPEA asserts that 0.07 lb/MMBtu meets the BACT requirement for NO_X emissions.

As discussed in Section 8.1.10, the SCR system may be inoperative for brief periods during startup due to insufficient flue gas flow rates and/or operating temperatures. During startup and shutdown periods, WPEA will utilize LNB and OFA as BACT with a NO_X BACT limit of 0.45 lb/MMBtu. Additionally, WPEA will minimize the number of startups that occur each year. Startups are expected to occur approximately 16 times per year per boiler.

[54] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.24.
[55] PSD Appeal No. 05-04, *In re: Newmont Nevada Energy Investment L.L.C., TS Power Plant*, December 21, 2005, p. 17.

10.5.3 Sulfur Dioxide (SO_2)

SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. While the SO_2 generally remains in a gaseous phase throughout the flue gas flow path, a small portion of the SO_2 may be oxidized to SO_3. The SO_3 can subsequently combine with water vapor to form H_2SO_4.

<u>Step 1 – Identify All Control Technologies</u>

A listing of potential control technologies is provided below. Per EPA's Draft NSR manual, control options incapable of meeting an applicable NSPS would not meet the definition of BACT and are not considered in the BACT analysis. Control technology combinations that have the potential to meet NSPS levels are addressed in the BACT analysis.

Lower Emitting Processes/Practices

Lower emitting processes/practices for control of SO_2 emissions are pre-combustion technologies that have the potential to result in lower levels of SO_2 emissions. Lower emitting processes/practices include the following:

<u>Coal Selection</u>

Coal-fired boiler SO_2 emissions result from the oxidation of sulfur contained in the coal during the combustion process. Therefore, the potential for SO_2 formation can be reduced by firing coal with a low sulfur content. Coal reserves in Wyoming's Powder River Basin are considered low sulfur coal reserves.[56] Additionally, Colorado and Utah bituminous coals are also considered low sulfur coals.

<u>Coal Cleaning</u>

Coal normally contains quantities of inorganic elements such as iron, aluminum, silica, and sulfur. These elements occur primarily in ash-forming mineral deposits embedded within the coal but are also present to a lesser degree within the organic coal structure. Coal cleaning is a process that removes this mineral ash matter from the coal after it is extracted from the ground.

The amount of ash, the manner in which it is included in the coal assemblage, and the degree to which it can be removed vary widely with different coals. The application and extent of coal cleaning depends on the particular mine and mining technique. Eastern coals are typically cleaned because Eastern deep mines produce a raw coal product typically containing 25% to 60% ash that cannot be sold without cleaning.[57] Conversely, surface mines tend to employ coal cleaning less often due to the effectiveness of overburden removal and the thickness of the coal seam.

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[56] U.S. EPA, Office of Air and Radiation, Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model, EPA Document No. EPA 430/R-02-004, Table 8.1, March 2002.
[57] Coal information from Energy Ventures Analysis, Inc., July 13, 2006.

Coal Refining

Subbituminous coal may contain significant amounts of bound moisture and other inorganic elements such as sulfur and nitrogen. Coal refining is a new process that employs both mechanical and thermal means to increase the quality of the coal by removing moisture, sulfur, nitrogen, and heavy metals. The thermal processing involves high pressure and temperature conditions to fracture mineral inclusions in the coal, removing included rock, pyritic sulfur, and moisture. As a result of the thermal process, the physical properties of the coal are modified to increase the heat rate, lower the moisture, and lower the ash content.[58]

Add-On Controls

Add-on controls for SO_2 reduction are post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. The technologies are often referred to as flue gas desulfurization (FGD) systems. Add-on controls include the following:

Wet Scrubber

The wet scrubber is a once-through wet technology. In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport/disposal.

The wet scrubber can be further classified on the basis of the reagents used and the by-products generated. The typical reagents are lime and limestone. Additives, such as magnesium, may be added to the lime or limestone to increase the reactivity of the reagent. Seawater has also been used as a reagent since it has a high concentration of dissolved limestone. The reaction by-products are calcium sulfite and/or calcium sulfate. The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced depending on the desired by-product. The most common wet scrubber application utilizes limestone as the reagent and forced oxidation of the reaction by-products to form calcium sulfate.

Regenerable Wet Scrubber

The regenerable wet scrubber is a regenerable wet technology that uses sodium sulfite, magnesium oxide, sodium carbonate, amine, or ammonia as the sorbent for removal of SO_2 from the flue gas. The spent sorbent is regenerated to produce concentrated streams of SO_2 or other sulfur compounds which may be further processed to produce other products. These FGD technologies may require additional flue gas treatment prior to the SO_2 absorption process in order to remove other flue gas constituents such as hydrogen chloride and hydrogen fluoride that may affect the sorbent and/or final by-product. Regenerable wet scrubbers achieve an SO_2 emissions reduction equivalent to that of a non-regenerable wet scrubber.

[58] Factsheet, *What is K-Fuel™*, http://www.kfx.com/fact_sheets/WhatIsK-Fuel.PDF.

Spray Dryer Absorber (Dry Scrubber)

The dry scrubber is a once-through dry technology. In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a dry form upon leaving the system and are subsequently captured in a downstream particulate collection device, typically a baghouse.

Circulating Dry Scrubber (CDS)

The CDS is a once-through dry technology. In a CDS, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and SO_2. The by-products leave the absorber in a dry form with the flue gas and are subsequently captured in a downstream particulate collection device.

Limestone Injection Dry Scrubbing (LIDS)

The LIDS technology combines furnace sorbent injection (FSI) and dry scrubber technologies. In the LIDS system, limestone is injected into the furnace and a spray dryer absorber is installed between the air heater and particulate collection device. The reagent used in the spray dryer is a hydrated reaction by-product recycled from the particulate collection device.

Activated Carbon Bed

The only potentially applicable regenerable dry technology is based on the use of activated carbon. In this FGD process, the activated carbon is present in a moving bed through which the flue gas flows. The activated carbon serves as the sorbent for removal of the SO_2. As the activated carbon becomes saturated with SO_2, it is regenerated, and the SO_2 is released as a stream of gaseous SO_2.

Electro-Catalytic Oxidation (ECO)

ECO is a multi-pollutant control technology under development by Powerspan Corporation. According to the company's website,[59] ECO is a multi-pollutant control technology that simultaneously controls SO_2, NO_X, Hg, and $PM_{2.5}$. The ECO process is located downstream of a plant's primary particulate removal device (electrostatic precipitator or fabric filter). The process includes a reactor that oxidizes the gaseous pollutants; a scrubber that removes NO_X, SO_2, and the oxidizer reactor products; and a wet electrostatic precipitator that captures the oxidized pollutants.

In 2005, the ECO technology completed a 180-day pilot testing run at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio. The pilot unit processed a flue gas slipstream that represented approximately one-third of the exhaust flow from a 156-MW front wall-fired boiler combusting coal.[60]

[59] http://www.powerspan.com/technology/scrubber_overview.shtml.
[60] http://www.powerspan.com/technology/scrubber_demonstration.shtml.

Pahlman Process

The Pahlman Process is a multi-pollutant control technology that simultaneously controls NO_X and SO_2. EnviroScrub Technologies, the developer of the Pahlman Process, has released only general information about the technology. According to the company's website, the process is located downstream of the particulate control device and utilizes a spray dryer absorber where a proprietary Pahlmanite™ scrubber material contacts the exhaust stream. The exhaust stream then passes through a "baghouse reaction chamber" where the Pahlmanite™ material is removed prior to the final exhaust stack. This technology is currently in the pilot stage of development, and the company operates a trailer-mounted pilot demonstration unit that can process coal-fired boiler exhaust slip streams of up to 2,000 scfm.[61]

Furnace Sorbent Injection (FSI) + Wet Scrubber

One potential control technology combination is FSI in conjunction with a wet scrubber. FSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb SO_2. In the FSI technology, the reagent is injected directly into the furnace and the reaction product is collected in the downstream particulate collection device. FSI has been shown to achieve as high as 72% SO_2 removal for combustion of coal containing 3% sulfur,[62] although the control efficiency would be expected to be less for lower-sulfur coal combustion.

FSI could presumably be used in conjunction with a wet scrubber.

Duct Sorbent Injection (DSI) + Wet Scrubber

One potential control technology combination is DSI in conjunction with a wet scrubber. DSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb SO_2. In the DSI technology, the reagent is injected into the ductwork between the air heater and particulate collection device. DSI has been shown to achieve 50 to 70% SO_2 removal.[63]

DSI could presumably be used in conjunction with a wet scrubber.

Duct Sorbent Injection (DSI) + Dry Scrubber

One potential control technology combination is DSI in conjunction with a dry scrubber. DSI could presumably be used in conjunction with a dry scrubber.

The following are not considered as potential stand-alone BACT control technologies since they would not be able to achieve the NSPS Da SO_2 emission limit of 1.4 lb/MW-hr[64] (0.15 lb/MMBtu for the WPEA coal-fired boilers).[65]

[61] http://www.enviroscrub.com/pilot.asp, April 27, 2006.
[62] Nolan, Paul S., The Babcock & Wilcox Company, *Flue Gas Desulfurization Technologies for Coal-Fired Power Plants,* Presented at the Coal-Tech 2000 International Conference.
[63] U.S. Department of Energy, *Clean Coal Technology – The Investment Pays Off,* 1999, http://www.fe.doe.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/Investment_pays_off.pdf.
[64] 40 CFR §60.43Da(i)(1).

- Coal Cleaning
- Furnace Sorbent Injection (FSI)
- Duct Sorbent Injection (DSI)

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable SO_2 control technologies identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on PC-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[66] A technology that has not been demonstrated on PC-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Coal Selection

Coal selection is a demonstrated method for minimizing the amount of sulfur available for SO_2 formation. Low sulfur PRB coal is available for use at the Facility. Additionally, low sulfur bituminous coals from Colorado and Utah are available. For this reason, the use of low sulfur coals is considered technically feasible.

Coal Cleaning

Coal cleaning is a demonstrated technology for reducing the amount of sulfur present in the coal in some situations. Coal cleaning provides a benefit for coal containing significant overburden or for high-sulfur eastern bituminous coals containing appreciable amounts of pyritic sulfur. However, PRB coal is surface mined from thick coal seams with very little overburden. The PRB coal mining techniques produce a coal product with very little rock and non-combustible material, other than what is bound in the coal. PRB coal contains low sulfur levels, typically below 1%, and low ash levels, typically below 6%. For these reasons, coal cleaning is not typically performed on PRB coal, and WPEA is not aware of any large-scale PRB coal cleaning operations in existence. Additionally, Utah and Colorado coals are not normally cleaned due to the low characteristic ash contents of these coals (typically 8%-11%).[67]

Due to the lack of coal cleaning facilities, there is currently no reliable source of cleaned western coal to supply the WPEA Facility. Since a sufficient supply of cleaned western coal is not available, coal cleaning is determined to be technically infeasible.

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[65] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.12.
[66] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.
[67] Coal information from Energy Ventures Analysis, Inc., July 13, 2006.

Coal Refining

Coal refining is not a demonstrated technology for controlling SO_2 emissions from large-scale PRB coal combustion. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

A company known as KFx is the only vendor known to offer refined PRB coal. This refined product is marketed under the name "K-Fuel™" and was first reported as being produced in commercial quantities in December 2005.[68] The first two production runs were reported to have produced 200 tons (i.e., enough fuel to supply the WPEA boilers for approximately 13 minutes). According to the company's website (http://kfx.com), the facility will only be able to produce 750,000 tons annually, once operational, a level below the annual coal throughput for the proposed WPEA Facility.

Based on the lack of refined PRB coal production capacity, coal refining is not considered an available technology for SO_2 emissions reduction. Therefore, per EPA's Draft NSR Workshop Manual, coal refining is determined to be technically infeasible for PRB coal.

WPEA is not aware of refining being applied to Colorado or Utah bituminous coal due to the lower moisture contents and higher heating values already shown by those fuels. Thus, coal refining is technically infeasible for Colorado and Utah bituminous coals.

Wet Scrubber

Wet scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers. Wet scrubbers that use limestone, lime, magnesium-enhanced lime, forced oxidation, and inhibited oxidation are all considered technically feasible control technologies. Wet scrubbers using seawater are determined to be technically infeasible because the Facility is located over 100 miles from the closest source of seawater.

Regenerable Wet Scrubber

Feasibility evaluations for the various regenerable wet scrubber configurations are presented below.

A) The sodium sulfite and ammonia-based technologies have been commercially demonstrated and are available from a number of suppliers. These technologies are considered technically feasible. As stated in Step 1 above, regenerable wet scrubbers achieve an SO_2 emissions reduction equivalent to that of a wet scrubber.

Regarding the evaluation of multiple control technologies that achieve an equivalent level of performance, EPA's Draft NSR Manual allows applicants to review only the lowest-cost option if several potential options achieve an

[68] http://kfx.com/documents/750KPlant123005.pdf.

essentially identical level of performance.[69] As stated above, a regenerable wet scrubber would be expected to achieve essentially identical environmental performance as a wet scrubber. Additionally, utilizing a regenerable wet scrubber would represent a higher cost than a wet scrubber (e.g., capital cost for regeneration process equipment). Therefore, in accordance with EPA guidance, WPEA will evaluate only the less costly option that achieves equivalent performance (i.e., WPEA will only carry wet scrubber technology forward in the analysis, as opposed to regenerable wet scrubber).

This BACT methodology was allowed by the NDEQ with no adverse comments from EPA during permitting of the Whelan Energy Center in March 2004.[70]

B) Only one application of the magnesium oxide scrubber technology was found. This application was at the Exelon Eddystone Station in Pennsylvania and was made possible because of a long-term commercial arrangement with a neighboring chemical company that regenerated the sorbent and sold the sulfur product. This has been the only application of this technology. Due to the lack of self-contained commercial applications of the magnesium oxide technology, WPEA expects that significant time delays and resource penalties would be required in order to develop this technology for the WPEA Facility. Per EPA's Draft NSR Manual, this is not the Agency's intent, and technologies that would present these problems are not considered available:

> *"A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique.*[71]

Accordingly, magnesium oxide technology is not considered available. Thus, magnesium oxide technology is determined to be technically infeasible.

C) No record of the commercial application of sodium carbonate and amine based regenerable technologies was found. Due to the lack of commercial application of these technologies, WPEA expects that significant time delays and resource penalties would be required in order to develop these technologies for the WPEA Facility. Per EPA's Draft NSR Manual, this is not the Agency's intent.[72] Accordingly, these technologies are not considered available. Thus, sodium carbonate and amine-based technologies are determined to be technically infeasible.

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[69] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.20.
[70] NDEQ Construction Permit Fact Sheet, Whelan Energy Center, March 2004.
[71] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.
[72] Ibid.

Dry Scrubber

Dry scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers. For these reasons, dry scrubbers are considered a technically feasible control technology.

Circulating Dry Scrubber (CDS)

CDS have only been domestically applied to two smaller coal-fired boilers: the 80-MW Neil Simpson Unit 2 and the 50-MW[73] LG&E Roanoke Valley Unit 2, both of which have experienced problems with lime utilization and corrosion.[74] CDS have not been demonstrated at the 530-MW scale of the WPEA Facility. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible. Regarding availability, EPA's Draft NSR Manual states the following:

> *"Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available..."*[75]

The size and scale differences between a 50-MW or 80-MW unit and a 530-MW unit would require significant design, testing, and modeling to evaluate the feasibility of scaling up CDS to the size of WPEA's proposed project. Scale-up efforts for fluidized bed systems are known to be particularly problematic and would be expected to require a significant level of effort and cost. Since the only demonstrated applications of the CDS technology have been on boilers approximately one-seventh the size of the WPEA boilers, CDS are not considered to have been applied to full-scale operations. Therefore, CDS are not considered available. Consequently, CDS are considered technically infeasible in accordance with EPA's Draft NSR Manual.

Limestone Injection Dry Scrubbing (LIDS)

LIDS is not a demonstrated technology for controlling SO_2 emissions from large-scale coal combustion. The LIDS technology is still undergoing significant research and development aimed at improving performance and increasing the scale of application.[76] Per EPA's Draft NSR Manual, technologies that have not yet been applied to full-scale operations are not considered available.[77] Since LIDS is still under development and is not commercially available for large-scale operations, this technology is not considered available. Consequently, the LIDS technology is determined to be technically infeasible.

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[73] Capacity from Powergen: http://www.pwrgen.com/DB_Hist/Projects_2.asp.
[74] Supplemental BACT information provided by WYGEN to the Wyoming Department of Environmental Quality, July 1, 2002.
[75] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.11.
[76] Nolan, Paul S., The Babcock & Wilcox Company, *Flue Gas Desulfurization Technologies for Coal-Fired Power Plants,* Presented at the Coal-Tech 2000 International Conference.
[77] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.11.

Activated Carbon Bed

Based on a review of the RBLC database, EPA's National Coal Database Spreadsheet, and available industry literature, activated carbon bed technology is not a demonstrated SO_2 removal technology for PC-fired boilers. WPEA has not located any commercial sales of activated carbon bed technology for SO_2 removal. EPA's Draft NSR Manual states the following:

> *"A control technique is considered available… if it has reached the licensing and commercial sales stage of development."*[78]

Since activated carbon bed technology for SO_2 removal has not reached the commercial sales stage of development, this technology is not considered available. Furthermore, activated carbon bed technology for SO_2 removal has not been deployed on an existing source with similar gas stream characteristics (i.e., flow rate, temperature, particulate loading, etc.). Therefore, activated carbon bed technology is not considered available. Consequently, activated carbon bed technology is determined to be technically infeasible for SO_2 removal.

Electro-Catalytic Oxidation (ECO)

The ECO technology is still in the pilot plant stage of development. To date, the only application of this technology has been a pilot facility processing a flue gas slip stream from a coal-fired boiler.[79] This technology has not been demonstrated for full-scale operations. EPA's Draft NSR Manual states the following regarding technologies in the pilot stage of development:

> *"…technologies in the pilot scale testing stages of development would not be considered available for BACT review."*[80]

Since the ECO technology has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available. Therefore, the ECO technology is determined to be technically infeasible.

Pahlman Process

The Pahlman Process has been demonstrated in small scale testing to reduce NO_X and SO_2 emissions from coal-fired boiler exhaust slip streams. However, the trailer mounted demonstration system is currently capable of treating up to 2,000 scfm of flue gas.[81] (This flow rate is far below the 1.28 MMscfm exhaust gas flow rate for each unit at the WPEA Facility.) Based on this information, the Pahlman Process is still in the pilot stage of development. EPA's Draft NSR Manual states the following regarding technologies in the pilot stage of development:

[78] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.
[79] http://www.powerspan.com/technology/scrubber_demonstration.shtml.
[80] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.
[81] http://www.enviroscrub.com/pilot.asp, April 27, 2006.

> *"…technologies in the pilot scale testing stages of development would not be considered available for BACT review."*[82]

Since the Pahlman Process has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available. Therefore, the Pahlman Process is determined to be technically infeasible.

<u>Furnace Sorbent Injection (FSI) + Wet Scrubber</u>

FSI could presumably be used in conjunction with a wet scrubber. However, the control efficiency of the wet scrubber would decrease due to lower inlet SO_2 concentrations, and there is no data available to indicate that the FSI + Wet Scrubber combination could achieve a lower SO_2 emission rate than a wet scrubber alone. Also, installing FSI would represent additional capital and operating costs with no assurance of improved environmental performance.

Regarding the evaluation of multiple control technologies that achieve an equivalent level of performance, EPA's Draft NSR Manual allows applicants to review only the lowest-cost option if several potential options achieve an essentially identical level of performance.[83] As documented above, FSI in conjunction with a wet scrubber would be expected to achieve essentially identical environmental performance as a wet scrubber alone. Additionally, utilizing an FSI system in conjunction with a wet scrubber would represent a higher cost than utilizing a wet scrubber alone (i.e., capital cost for FSI components and operating costs such as FSI reagent). Therefore, in accordance with EPA guidance, WPEA will evaluate only the less costly option that achieves equivalent performance (i.e., WPEA will only carry wet scrubber technology forward in the analysis, as opposed to FSI + wet scrubber).

This BACT methodology was allowed by the NDEQ with no adverse comments from EPA during permitting of the Whelan Energy Center in March 2004.[84]

<u>Duct Sorbent Injection (DSI) + Wet Scrubber</u>

DSI could presumably be used in conjunction with a wet scrubber. However, the control efficiency of the wet scrubber would decrease due to lower inlet SO_2 concentrations, and there is no data available to indicate that the DSI + Wet Scrubber combination could achieve a lower SO_2 emission rate than a wet scrubber alone. Also, installing DSI would represent additional capital and operating costs with no assurance of improved environmental performance.

Regarding the evaluation of multiple control technologies that achieve an equivalent level of performance, EPA's Draft NSR Manual allows applicants to review only the lowest-cost option if several potential options achieve an essentially identical level of performance.[85] As documented above, DSI in conjunction with a wet scrubber would be expected to achieve essentially identical environmental performance as a wet scrubber alone. Additionally, utilizing a DSI system in conjunction with a wet

[82] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.
[83] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.20.
[84] NDEQ Construction Permit Fact Sheet, Whelan Energy Center, March 2004.
[85] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.20.

scrubber would represent a higher cost than utilizing a wet scrubber alone (i.e., capital cost for DSI components and operating costs such as DSI reagent). Therefore, in accordance with EPA guidance, WPEA will evaluate only the less costly option that achieves equivalent performance (i.e., WPEA will only carry wet scrubber technology forward in the analysis, as opposed to DSI + wet scrubber).

This BACT methodology was allowed by the NDEQ with no adverse comments from EPA during permitting of the Whelan Energy Center in March 2004.[86]

Duct Sorbent Injection (DSI) + Dry Scrubber

In order for a DSI system to function effectively, humidification to a close approach to the adiabatic saturation temperature of the flue gas is required.[87] Therefore, installing a DSI system in conjunction with a dry scrubber would interfere with the ability of the spray dry scrubber to evaporate the moisture in the reagent slurry and function properly. Since the DSI system would interfere with operation of the dry scrubber, the DSI + dry scrubber combination is determined to be infeasible.

In summary, following SO_2 emission control technologies are carried forward to Step 3 of the BACT analysis:

- Coal Selection
- Wet Scrubber
- Dry Scrubber

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Since coal selection is a feasible option for all potential add-on control technologies, coal selection (i.e., the use of low-sulfur coal) is used as the base case for the control technology discussions presented in the remainder of the BACT analysis.

Ranking by Control Effectiveness

Technical publications, vendor information, permits and permit applications, and the RBLC database were reviewed to determine the range of reported control efficiencies for each of the technically feasible SO_2 reduction technologies identified in Step 2. The SO_2 control efficiencies and emission levels are listed in Table 10.7 below.[88]

[86] NDEQ Construction Permit Fact Sheet, Whelan Energy Center, March 2004.
[87] Nolan, Paul S., The Babcock & Wilcox Company, *Flue Gas Desulfurization Technologies for Coal-Fired Power Plants,* Presented at the Coal-Tech 2000 International Conference.
[88] This section of the BACT analysis focuses solely on the removal efficiency of SO_2; however, as addressed later in this document, total air emissions for dry scrubbing are less than those for wet scrubbing.

Table 10.7 – Ranking of Remaining SO_2 Control Technologies by SO_2 Removal Effectiveness

Control Option	Control Efficiency (1)	Control Effectiveness (lb/MMBtu) (2)
Wet Scrubber	90% to ≥95%	0.06 to 0.11
Dry Scrubber	90% to 95%	0.065 to 0.11
Low Sulfur Coal	Baseline	<1.2 (3)

Notes:

(1) Values from U.S. EPA, Controlling SO2 Emissions: A Review of Technologies, EPA/600/R-00/093, November 2000, and vendor-provided data.
(2) Minimum and maximum typical values from RBLC database search results.
(3) Represents compliance coal (any coal that emits less than 1.2 lb/MMBtu).

Although the high end of the wet scrubber control efficiency presented in Table 10.7 can be higher than that of a dry scrubber, median design efficiencies for wet and dry scrubbers are identical based on EPA findings.[89] Additionally, according to the most recent available Energy Information Administration (EIA) data, wet and dry scrubbers placed in service since 1990 have essentially identical average control efficiencies based on actual test data: 89.6% control for wet scrubbers and 89.8% control for dry scrubbers.[90]

The control efficiency of a given SO_2 control technology is dependent on the SO_2 content in the incoming flue gas stream, and the inlet SO_2 content is directly proportional to the sulfur content of the coal. In applications where a high sulfur coal is used, the control efficiency can be higher than in applications where a low sulfur coal is burned. For this reason, caution must be used when attempting to apply the reported control efficiency for one application to another application.

Summarizing these facts, NDEP recently stated in the Response to EPA Region 9 Comments on Draft Operating Permit to Construct AP4911-1349 for Newmont Nevada Energy Investments, LLC – TS Power Plant:

> *"Based on an EPA report and review of vendor information for wet and dry FGD processes, BAPC concluded that for higher sulfur coals wet scrubbing achieves better control, however, for lower sulfur Powder River Basin (PRB) coals, the efficiencies become so close as to be indistinguishable within their respective margins of error."*

The WPEA Facility is no different from the Newmont facility in this respect. Both facilities will utilize PC-fired boilers to combust low-sulfur western coals. Thus, the control efficiencies for wet scrubbers and dry scrubbers at the WPEA Facility are

[89] U.S. EPA, *Controlling SO2 Emissions: A Review of Technologies,* EPA/600/R-00/093, November 2000. Wet and dry scrubbers are both listed with a 90% median design efficiency in Table 4-1 of the referenced document.
[90] Average reported test results derived from Form EIA-767 "Steam-Electric Plant Operation and Design Report" 2004 reporting year, http://www.eia.doe.gov/cneaf/electricity/page/eia767.html.

expected to be indistinguishable within their respective margins of error based on NDEP's analysis for the Newmont facility.

Energy Impacts

This subsection discusses the energy impacts of the remaining SO_2 control options.

The primary energy impact for either option is a parasitic load on the system. A parasitic load refers to energy produced by the generator and used for an ancillary device. In order to send a desired amount of power to the transmission grid, a power plant must produce power in excess of the desired amount to compensate for the parasitic load. The end result of a higher parasitic load is higher emissions to produce the same amount of power for sale. The energy impacts for the SO_2 control options are presented in Table 10.8.

Table 10.8 – Summary of Energy Impacts for SO_2 Control Options

Control Option	Parasitic Load (%) (1)	Parasitic Load (MW) (2)	Notes
Wet Scrubber	2%	34.5	Higher parasitic load due to additional electric motor driven equipment such as recirculating pumps, waste dewatering pumps, reagent preparation equipment, and larger fans
Dry Scrubber	0.7%	11.1	--

Notes:
(1) Based on *Alstom Power WFGD Presentation*, September 3, 2001.
(2) For the 1,590-MW WPEA Facility.

Environmental Impacts

The environmental impacts list is organized by environmental impact type. The impacts are provided and discussed below.

Water Consumption. White Pine County, Nevada is considered an arid region receiving an annual rainfall of approximately 9 inches.[91] Thus, water consumption is an important consideration.

In a wet scrubber, water is consumed via the following uses:

- Cool and saturate the flue gas from approximately 300°F to 125°F (approximately 465 gpm/unit),
- Form the reaction products (approximately 25 gpm/unit),

[91] http://budget.state.nv.us/BR02/BR02Enviroreport.doc

- Wash the by-product (approximately 0 to 35 gpm/unit blowdown), and
- May be lost when water exits the system with a moist by-product.

In a dry scrubber, water is consumed via the following uses:

- Cool the flue gas from approximately 300°F to 165°F (approximately 344 gpm/unit) and
- Form the reaction products (approximately 6 gpm/unit).

Estimated water consumption requirements for the Facility are summarized in Table 10.9 below.

Table 10.9 – Estimated Water Consumption of Scrubbers for 1,590 MW Facility

Scrubber Type	Water Consumption (MMgal/year)	Incremental Consumption (MMgal/year)	Incremental Consumption (%)
Wet Scrubber	773 (1)	221	40%
Dry Scrubber	552 (1)	--	--

Note:

(1) Assumes 100% capacity factor. Based on engineering estimates and vendor information.

Air Impacts – Emissions. This subsection lists the air impacts for the SO_2 control options. Control efficiencies for SO_2 are listed in Table 10.7 above. Table 10.10 below shows the effectiveness of the SO_2 control options for controlling non-SO_2 pollutants.

Table 10.10 – Control Efficiency Values for Non-SO_2 Pollutants

Pollutant	Control Efficiency	
	Wet Scrubber (%)	Dry Scrubber (%)
H_2SO_4 Mist	45% (1)	92% (4)
$PM_{2.5}$	50% to 90% (2)	98% (2)
HF	44% (3)	95% (3)

Notes:

(1) As reported by AES, http://www.solvaychemicals.us/pdf/Trona_Products/PowerGen.pdf.
(2) Stationary Source Control Techniques Document for Fine PM, EPA452/R-97-001 and Development of Primary, Filterable, and Condensible PM10 and PM2.5 Emission Factors for the Factor Information and Retrieval (FIRE) System Database, Sept. 2003.
(3) EPA Document No. OAR-2002-0056-5736.
(4) Based on engineering estimates and vendor information.

As shown in Table 10.10, a dry scrubber would have lower emissions than a wet scrubber for the non-SO_2 pollutants. Differences in non-SO_2 emissions performance are discussed below.

H_2SO_4: Sulfuric acid mist emissions are higher with a wet scrubber system as compared to a dry scrubber/baghouse system. AES has reported H_2SO_4 removal averaging 45% for wet scrubbing.[92] The estimated H_2SO_4 removal efficiency for dry scrubbing is 92%. A more complete discussion of sulfuric acid mist is provided in Section 10.5.8.

Fine PM: A wet scrubbed system would generate additional emissions of $PM_{2.5}$. A wet scrubber system's absorbers are located downstream of the particulate control device. As a result, a wet scrubber system would emit fine particulates such as condensables and aerosols due to carryover from the absorbers' mist eliminators. $PM_{2.5}$ removal effectiveness for a wet scrubber system ranges from 50% to 90%. A dry scrubber system would be equipped with a fabric filter baghouse, which is estimated to remove over 98% of $PM_{2.5}$ emissions.[93]

Fine particulate emissions will be an even more significant issue in the future with the implementation of $PM_{2.5}$ regulations. According to the National Energy Technology Laboratory, "Rapid cooling at the wet FGD inlet creates submicron size sulfuric acid aerosols that cannot be removed efficiently by the wet FGD device creating increased PM fine emissions."[94]

HF: Hydrogen fluoride emissions would also be higher with a wet scrubber system. In its canvassing of information to prepare the Electric Utility Report to Congress, EPA was able to find two acceptable sets of test results for HF emissions, one each for wet and dry scrubbing. The results of those tests were that a wet scrubber was capable of removing 44% of the HF while a dry scrubber demonstrated removal of 95%.[95] Additional discussion on emissions of HF is provided in Section 10.5.7.

A summary of emissions per unit for each control option is presented in Table 10.11 below.

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[92] http://www.solvaychemicals.us/pdf/Trona_Products/PowerGen.pdf

[93] Stationary Source Control Techniques Document for Fine PM, EPA452/R-97-001 and Development of Primary, Filterable, and Condensible PM10 and PM2.5 Emission Factors for the Factor Information and Retrieval (FIRE) System Database, Sept. 2003.

[94] http://www.netl,doe,gov/coal/E&WR/pm/control.html

[95] EPA Document No. OAR-2002-0056-5736.

Table 10.11 – Facility-Wide Emissions Related to SO_2 Control Options

Pollutant	Total Emissions from the PC-Fired Boilers [3]	
	Dry Scrubber (tpy)	Wet Scrubber (tpy)
SO_2 [1]	4,455	2,742 [2]
H_2SO_4	164	1,124
Fluorides as HF	66	754
Efficiency Related Emissions [4]		
CO	-	134
NO_X	-	62
SO_2	-	36
PM/PM_{10}	-	34
VOC	-	3
H_2SO_4	-	15
Total	**4,685**	**4,904**

Notes:

(1) Assumes coal with an average sulfur content of 0.32% (the average of 12 PRB coal specifications obtained as the design coal basis for the Plum Point Energy Station in Osceola, Arkansas). For this coal, a dry scrubber would achieve 0.065 lb/MMBtu, and a wet scrubber is assumed to achieve 0.04 lb/MMBtu.

(2) For the emissions comparison, a conservatively low wet scrubber SO_2 emission factor of 0.04 lb/MMBtu is used, corresponding to 95% control with 0.32% sulfur coal. This low emission factor reflects NDEP's decision on the Newmont permit requiring control efficiency values as enforceable permit limits (i.e., if NDEP required 95% control for a wet-scrubbed system firing 0.32% sulfur coal, the resulting SO_2 emission limit would be 0.04 lb/MMBtu). There are currently no wet scrubber systems with permitted or proposed SO_2 BACT limits less than 0.06 lb/MMBtu. Thus, the concept of achieving 0.04 lb/MMBtu as SO_2 BACT remains speculative and is only presented here to create the most conservative comparison between the two technologies

(3) Assumes 100% annual capacity factor.

(4) Efficiency-related emissions represent the additional emissions associated with having to use more fuel to compensate for the higher parasitic load from wet scrubbing. Dry scrubbing is considered the base case for efficiency related emissions.

As shown in Table 10.11, dry scrubbing would result in 219 tpy less overall emissions than wet scrubbing.

Air Impacts – Fugitive Emissions. Fugitive PM/PM_{10} emissions from a wet scrubbed system occur from the storage (typically stored in exposed piles) and handling (numerous handling points) of the limestone and the handling and disposal of the large amount of byproducts. Byproducts from a wet scrubber system will be approximately 53,300 tons per year greater than from a dry scrubber system.

Lime used in a dry scrubber system would be stored in enclosed silos with no fugitive emissions. Emissions from the silos would be controlled with vent filters.

Air Impacts – Visible Plume. A wet scrubber system would emit a visible steam plume. During warm, dry weather, the plume should dissipate within a few hundred yards of the stack discharge. During cooler weather or humid conditions, the steam plume will be visible for a greater distance from the stack. The plume may be considered unfavorable from an aesthetic perspective. Properly operated dry scrubbers do not typically emit a visible plume.

Air Impacts – Concentrations. On an equal emission rate basis, the near-field ground level concentrations for all pollutants will generally be higher with a wet scrubber system compared to a dry scrubber system. The higher ground level concentrations result because a wet scrubber system produces a cooler, wetter, less buoyant plume.

Water Impacts – Wastewater. Wet scrubbers produce a wastewater stream. The amount and characteristics of the wastewater are dependent on the coal type and the gypsum disposal method. If saleable gypsum is produced, it must meet moisture and chloride specifications resulting in greater system blowdown and increased water usage. Salable gypsum also requires dewatering resulting in additional power consumption. Depending on solid waste disposal restrictions, disposable gypsum may result in zero wastewater if all of the chlorides and excess moisture can be accepted in the solid waste disposal area. Blowdown may still be required to maintain water chemistry in the wet scrubber absorber vessel. A blowdown stream of 70 gpm (all three units) would result in an additional 42 acres of evaporation pond surface area.

Wastewater from a wet scrubbed plant would have higher concentrations of dissolved and suspended chemicals potentially requiring more specialized water handling and treatment equipment. In addition, water treatment might be required for the wet scrubber plant's wastewater prior to disposal in the evaporation pond to remove heavy metals (which are 15% to 25% higher for a plant with wet scrubbing than a plant with dry scrubbing) and chlorides (which are 547% higher for a plant with wet scrubbing than with a plant with dry scrubbing).[96] Costs for wastewater treatment have not been identified but may be substantial.

A dry scrubber system does not have a blowdown or wastewater stream, and the reaction products are dry such that they can be transported with pneumatic systems.

Solid Waste Impacts. Wet scrubbers all rely on the reaction of calcium in the reagent to remove SO_2 from the flue gas. An inhibited oxidation system will produce a high-solids calcium sulfite stream that is more difficult to dewater and has very little potential for commercial use and is typically disposed of in a solid waste disposal facility. A forced oxidation system produces calcium sulfate (synthetic gypsum) which may be marketable depending on its quality and local market requirements.

Dry scrubbers also produce a solid byproduct stream with little commercial value that is normally disposed of in a solid waste disposal facility. Scrubber solid waste production for each 530-MW unit is summarized in Table 10.12.

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[96] Wet FGD wastewater characteristics based on "Coal-Fired Power Station Effluents," IEA Coal Research, The Clean Coal Centre.

Table 10.12 – Solid Scrubber Waste Production

Scrubber Type	Scrubber Waste Produced per Unit (tons per year)	Incremental Waste Produced for 3 Units (tons per year)	Incremental Waste Disposal Space for 3 Units (acre-feet/year)
Wet Scrubber	217,538 (1)	76,017	801
Dry Scrubber	192,199 (1)	--	--

Notes:
(1) Assumes 100% capacity factor. Based on engineering estimates and vendor information.

Economic Impacts

Per EPA's Draft NSR Manual, average and incremental cost effectiveness are the two economic criteria that are considered in Step 3 of the BACT analysis.[97] A summary analysis of the economic impacts providing the average and incremental cost of the use of a wet scrubber system is summarized in Table 10.13 below. Table 10.14 provides additional details of the analysis.

Table 10.13 – Summary of Economic Impacts for SO_2 Control Options

Control Option	Emissions per Unit (tpy)	Emissions Reduction Over Base Case (tpy)	Total Annualized Cost over Baseline ($/year)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Wet Scrubber	898	16,617	$25,654,000	$1,544	$20,114
Dry Scrubber	1,459	16,056	$14,390,000	$896	$896
Baseline	17, 515	--	--	--	--

Notes: Since the boilers will be designed assuming the use of PRB coal, the baseline for the economic analysis is coal with 0.32% sulfur by weight (the average of 12 PRB coal specifications obtained as the design coal basis for the Plum Point Energy Station in Osceola, Arkansas).
Costs determined for a 530 MW unit with a 100% capacity factor.
Wet scrubber assumes 95% removal.
Dry scrubber assumes 92% removal.

[97] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.31.

Table 10.14 – Detail of Economic Impacts for SO_2 Control Options Per 530-MW Unit

Parameter	Dry Scrubber	Wet Scrubber	Notes
Capacity, MW	530	524	
SO2 Content, lb/MMBtu	0.78	0.78	
Removal	92%	95%	
Emission Rate, lb/MMBtu	0.065	0.04	
Direct capital costs			(1)
Purchased Equipment	$45,764,000	$80,391,000	
Direct installation	$8,131,000	$15,191,000	
Indirect capital costs	$15,748,000	$27,854,000	(2)
Total Capital Cost	$69,643,000	$123,436,000	
Total capital required, $/kW (net)	$131	$235	
Annual costs			
Lost energy sale revenue	$1,766,000	$5,047,000	(3)
Limestone	--	$1,302,000	
Lime	$1,579,000	--	
Waste	$197,000	$288,000	
Labor	$765,000	$1,148,000	(4)
Maintenance material	$539,000	$956,000	(5)
Indirects	$1,393,000	$2,469,000	(6)
Capital recovery	$8,150,000	$14,444,000	
Total annual costs	$14,390,000	$25,654,000	
Incremental Annual costs	--	$11,265,000	
SO2 emissions, tpy	1,459	898	
Incremental removal, tpy		560	
Incremental cost, $/ton		$20,114	

Notes:
(1) Includes the scrubber and baghouse.
(2) Includes AFUDC, contingency, engineering, construction and field expenses, startup, and performance tests.
(3) Lost energy revenue caused by auxiliary load consumed by the scrubber system.
(4) An additional 8 operations and maintenance personnel are assumed for a dry scrubber and an additional 12 are assumed for a wet scrubber.
(5) Maintenance material equal 1% of direct capital costs.
(6) Includes administrative and insurance.

The above economic assessment was based on the use of a limestone forced oxidation system since this system has the most favorable economics of all the wet scrubber technologies. While a wet scrubber system would require only one absorber vessel per unit, there is little economy of scale with wet scrubber absorber vessels. The vessel is sized to meet the gas velocity and residence time needed to allow sufficient contact time between the gas and the limestone slurry for saturation; more levels and/or spray nozzles are required for a larger vessel in order to ensure gas saturation increasing piping and pump costs. In addition, the reaction tank at the bottom of the absorber must be larger requiring higher foundation loading and thus more foundation costs. The materials of construction for the wet scrubber vessel and reaction tank are alloys and corrosion resistant materials due to the saturated, corrosive environment. Alloys and corrosion resistant materials are significantly more expensive than standard materials of construction such as carbon steel and concrete that are used by a dry scrubber system. The differences in material are shown in Table 10.15 below.

Table 10.15 – Summary of Construction Materials of Scrubbers

Scrubber Type	Absorber	Piping	Tanks	Stack Liner
Wet Scrubber	Stainless steel C275 (nickel alloy) Concrete w/Stebbins tile	Stainless steel Alloys FRP Rubber lined carbon steel	Flakeglass lined carbon steel	C276 Acid Brick
Dry Scrubber	Carbon steel	Carbon steel	Most carbon steel with some rubber lined	Carbon steel with some stainless at exit

Note: Relative prices for alternate materials[98]

Carbon steel	– 1.0
Rubber lined carbon steel	– 2.26
Stainless steel	– 1.8 to 2.1
C276	– 4.55
Concrete/block	– 2.63

<u>Step 4 – Evaluate Most Effective Controls and Document Results</u>

The potential energy, environmental, and economic impacts of the control technologies are evaluated below, starting with the most effective control. Where appropriate, comparisons are made between wet and dry scrubbing technologies.

As discussed in Step 3, an EPA report, the most recent available EIA data, and a recent NDEP response to comments document all indicate the control efficiencies of wet and dry scrubbers are indistinguishable within their respective margins of error for processes using low sulfur coals. However, wet scrubbing is evaluated as the top option since wet scrubbers are perceived as more efficient at removing SO_2 emissions.

<u>Wet Scrubber</u>

A case-by-case consideration of energy, environmental, and economic impacts for wet scrubbing is presented below.

[98] Milobowski, M.G., “Wet FGD System Materials Cost Update,” Babcock & Wilcox, 1997

Energy Impacts

As documented in Step 3, a wet scrubber would demand a parasitic load of up to 34.5 MW for the Facility. This would be enough energy to provide for approximately 29,000 homes.[99] Thus, the energy requirements for wet scrubbing represent a negative energy impact. Installing a control technology that would consume an energy equivalent of 29,000 homes would not represent a judicious use of energy by the WPEA Facility. Additionally, as listed in Table 10.11 and discussed below, a high level of efficiency-related emissions would be required to overcome the parasitic load from a wet scrubber.

Environmental Impacts

Multiple environmental impacts were listed for wet scrubbing in Step 3. An evaluation of the environmental impacts is included below, organized by environmental impact type.

Water Impacts – Water Consumption. As discussed in Step 3, White Pine County is considered an arid region due to annual rainfall of only 9 inches. Thus, water consumption is an important consideration in the BACT determination.

In the October 28, 2005, Clean Air Mercury Rule (CAMR) Federal Register notice, EPA recognized that water availability must play a role in control technology determinations for areas that receive less than 25 inches of precipitation per year. EPA stated that for new subbituminous coal-fired units located in an area receiving less than 25 inches of precipitation per year, Best Demonstrated Control Technology (BDT) is considered a dry FGD system.[100]

Multiple state agencies have acknowledged increased water consumption for wet scrubbers as a negative environmental impact affecting BACT determinations. For example, the Wyoming Department of Environmental Quality (WDEQ) Permit Analysis for the Neil Simpson Unit II listed an additional 20% to 30% more water required for a wet scrubber. The WDEQ analysis stated that water usage was a primary environmental concern and of special importance in that semi-arid part of the country.[101] Additionally, the Montana Department of Environmental Quality (MDEQ) permit analysis for the Roundup power plant estimated that wet scrubbing for the two 390 MW units proposed would require 420.5 million gal/year in comparison to 304.8 million gal/year required for dry scrubbing (38% more). MDEQ listed the higher water consumption rate among the determining collateral environmental impacts that eliminated wet scrubbing from consideration as BACT.[102]

[99] http://www.utilipoint.com/issuealert/print.asp?id=1728
[100] 70 FR 62216, October 28, 2005.
[101] Wyoming Department of Environmental Quality, Permit Analysis for Neil Simpson Unit II, April 14, 1993.
[102] Montana Department of Environmental Quality, Permit No. 3182-00, July 21, 2003.

As shown in Step 3, a wet scrubber system has an incremental consumption of 221,000,000 more gallons of water per year. That additional water would be capable of supporting approximately 841 additional homes.[103] It is in the best interest of this arid region to minimize water consumption and allow for future residential, commercial, and industrial growth in the area. WPEA has demonstrated this commitment to minimal water use by selecting a semi-dry cooling tower system to significantly reduce the amount of water consumed by the Facility.

Considering that the Facility will be located in an arid region, the water consumption impacts for wet scrubbing represent a negative environmental impact.

Air Impacts – Emissions. While estimated SO_2 emissions would be lower for wet scrubbing, a wet-scrubbed system would result in higher levels of total air emissions, particularly for other PSD pollutants and hazardous air pollutants (HAPs). Pursuant to EPA's Draft NSR Manual, a PSD permitting authority should consider the effects of a given control alternative on emissions of toxics or hazardous pollutants not regulated under the Clean Air Act.[104]

As detailed in Step 3, emissions of HF (a HAP), H_2SO_4 (a PSD pollutant), and criteria pollutants (excluding SO_2) are a negative environmental impact for wet-scrubbed systems. For the 1,590-MW Facility, additional emissions of these pollutants would be significantly higher (see Table 10.11):

HF (a HAP):	688 tpy higher for wet scrubbing
H_2SO_4:	960 tpy higher for wet scrubbing
Criteria Pollutants: (excluding SO_2)	233 tpy higher for wet scrubbing

Emitting significantly higher levels of HAPs (i.e., HF) and other PSD pollutants (i.e., H_2SO_4 and non-SO_2 criteria pollutants) with a wet scrubber would be an undesirable compromise for the marginally better SO_2 performance that might be achievable. EPA's Draft NSR Manual reinforces this determination:

"On occasion, consideration of toxics emissions may support the selection of a control technology that yields less than the maximum degree of reduction in emissions of the regulated pollutant in question. An example is the municipal solid waste combustor and resource recovery facility that was the subject of the North County remand. Briefly, BACT for SO_2 and PM was selected to be a lime slurry spray drier followed by a fabric filter. The combination yields good SO_2 control (approximately 83 percent), good PM control (approximately 99.5 percent) and also removes acid gases (approximately 95 percent), metals, dioxins, and other unregulated pollutants. In this instance, the permitting authority determined that good balanced control of regulated and unregulated pollutants took priority over

[103] Based on 1996 AWWA survey for Nevada homeowners.
[104] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.50.

achieving the maximum degree of emissions reduction for one or more regulated pollutants. Specifically, higher levels (up to 95 percent) of SO_2 control could have been obtained by a wet scrubber."[105]

Furthermore, as discussed in Step 3, fine particulate emissions would be higher with wet scrubbing. The emission of fine particulate will be an even more significant issue in the future with the implementation of $PM_{2.5}$ regulations.

Finally, even after taking into account the marginally better SO_2 removal efficiency associated with wet scrubbing, WPEA estimates that wet scrubbing would result in 219 tons per year more total emissions as reflected in Table 10.11.

Air Impacts – Fugitive Emissions. As discussed in Step 3, fugitive PM/PM_{10} emissions from a wet scrubbed system would result from the storage and handling of the limestone and the handling and disposal of the large amount of byproducts. These low-release height fugitive emissions typically manifest their highest ambient concentrations just beyond the facility boundaries. While fugitive dust would not cause an exceedance of the National Ambient Air Quality Standards (NAAQS), activities that result in fugitive dust emissions should be avoided to the extent practicable.

Air Impacts – Visible Plume. As discussed in Step 3, a visible plume can result from a wet scrubber under a variety of ambient conditions. Visible plumes are often perceived negatively by the public and are considered undesirable.

Air Impacts – Concentrations. As discussed in Step 3, a wet scrubber would emit a cooler plume, which would result in less plume rise and higher ambient impacts. This is an undesirable environmental impact.

Water Impacts – Wastewater. As discussed in Step 3, wet scrubbers produce a wastewater stream due to the dewatering of the scrubber byproduct. Wastewater from a wet scrubbed plant would have higher concentrations of heavy metals and chlorides that might have to be treated before discharge to the Facility's evaporation pond. Additionally, a wet-scrubbed system would require a larger evaporation pond.

Creating wastewater concerns with a wet scrubber would be an undesirable compromise for the marginally better SO_2 performance that might be achievable.

Solid Waste Impacts. As discussed in Step 3, a wet-scrubbed facility would produce more solid waste. The extra 76,018 tons per year produced by a wet scrubbed facility would consume an additional 801 acre-feet of disposal area space.

[105] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.53.

> Significantly increasing solid waste production would not be a desirable compromise for the marginally better SO_2 air emissions performance that might be achieved with a wet scrubber.

<u>Economic Impacts</u>

The following evaluation considers the cost effectiveness of the primary control options. The SO_2 BACT determination does not rest entirely or even principally on the economic impacts as is evident by the documented environmental and energy impacts, which by themselves provide sufficient justification for the control technology decision on wet scrubbing.

EPA has consistently stated that the economic analysis should evaluate the average cost and the incremental cost as part of the analysis. For example, EPA's Draft NSR Manual directs that, "[i]n addition to the average cost effectiveness of a control option, incremental cost effectiveness between control options should also be calculated. The incremental cost effectiveness should be examined in combination with the average cost effectiveness in order to justify elimination of a control option."[106] In the Final Order Inter-Power of New York, the Judge stated that "[u]ltimately, a control option may be rejected where the costs for the option 'would be disproportionately high when compared to the costs normally associated with BACT for the type of facility (or BACT control costs in general) for the pollutant."[107]

Multiple state agencies have acknowledged incremental cost as a contributing factor in BACT determinations. For example, in the Permit Analysis for the Neil Simpson Unit II, WDEQ stated that the high incremental costs associated with a wet scrubber coupled with the high capital costs of the system made a dry scrubber system a more economically attractive alternative.[108] Additionally, NDEP recently stated that the incremental cost associated with wet scrubbing for Newmont's proposed facility would far exceed the environmental benefit from the modest reduction in SO_2 emissions that might be possible.[109]

The average and incremental costs for wet scrubbing are provided in Table 10.13 above. While the average cost for a wet scrubber in Step 3 is \$1,544 per ton, the incremental cost is \$20,114 per ton. For comparison, Table 10.16 below lists incremental costs for wet scrubbing at other proposed units where the incremental cost was noted as a negative economic impact that, when considered in conjunction with negative environmental and energy impacts, contributed to the ultimate decision to reject wet scrubbing as BACT.

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[106] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.41. Additional support for the importance of considering both average and incremental cost are provided in the following: Final Order, In Re Inter-Power of New York, Inc., March 16, 1994 and January 19, 2001 Memorandum from John S. Seitz, Director to Air Division Directors, Regions I-X, "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects."
[107] PSD Appeal Number 92-8 and 92-9, page 136.
[108] Wyoming Department of Environmental Quality, Permit Analysis for Neil Simpson Unit II, April 14, 1993.
[109] Response to EPA Region 9 Comments on Draft Operating Permit to Construct AP4911-1349 for Newmont Nevada Energy Investments, LLC – TS Power Plant.

Table 10.16 - Comparison of Incremental Costs for Wet Scrubbers at Other Low-Sulfur Coal Units

Project	Wet Scrubber Incremental Cost ($/ton)	Date
Council Bluffs Unit 4	$6,132	2002
Plum Point	$6,900	2001
Sand Sage	$7,363	2001
Sandy Creek	$8,083	2003
Longleaf	$8,205	2004
Neil Simpson II	$8,864	1993
Southwest Power Station	$10,029	2003
Wygen 2	$12,190	2002
Wygen I	$12,191	1996
White Pine	$20,114	Proposed
Commanche	$23,579	2005
Newmont	$26,188 (0.48% S) [1] $68,894 (0.32% S)	2005

Notes:

(1) Newmont's maximum allowable sulfur is 0.48%. In NDEP's preliminary determination, the calculation was conducted using the design sulfur content of 0.32%.

As shown in Table 10.16 above, incremental costs listed as negative economic impacts have ranged from $6,100 to $69,000. Thus, the wet scrubbing incremental cost of $20,114 per ton for the WPEA Facility is within the range of incremental costs contributing to BACT decisions in favor of dry scrubbing at other facilities. Therefore, the incremental cost of applying wet scrubbing is a negative economic impact that, in combination with the negative energy and environmental impacts, contributes to the determination that a wet scrubber is not BACT for the WPEA Facility.

Based on the negative energy, environmental, and economic impacts documented above, wet scrubber technology is not selected as SO_2 BACT for the PC-fired boilers. Considering the marginal SO_2 control efficiency that might be gained from the use of a wet scrubber, the additional energy consumption, water consumption, air emissions, visible plume, wastewater impacts, solid waste generation, and high incremental cost would be an undesirable compromise. Since wet scrubber technology is not selected as BACT, dry scrubber technology is evaluated next in the top-down process.

Dry Scrubber

A case-by-case consideration of energy, environmental, and economic impacts for dry scrubbing is presented below.

Energy Impacts

As shown in Step 3, dry scrubbing presents an energy penalty of approximately 0.7% of gross generation. This is consistent with other control technology types and does not preclude the selection of this technology as BACT.

Environmental Impacts

As shown in Step 3, dry scrubbing results in lower overall air emissions. Of importance in an arid region, dry scrubbing uses significantly less water. Additionally, dry scrubbing does not create a wastewater or blowdown stream. Dry scrubbers produce less solid waste. Lime fed to dry scrubber systems creates only minimal emissions since the lime is stored in silos. These environmental impacts do not preclude the selection of this technology as BACT.

Economic Impacts

As shown in Step 3, the cost of controlling SO_2 with a dry scrubber is $896 per ton. This economic impact does not preclude the selection of this technology as BACT.

Since no energy, environmental, or economic impacts preclude its selection, WPEA selects dry scrubbing in combination with low sulfur coal as SO_2 BACT for the PC-fired boilers.

Step 5 – Select BACT

WPEA selects dry scrubbing in combination with low sulfur coal as SO_2 BACT for the PC-fired boilers. Since the SO_2 emission rate depends on the sulfur content of the coal combusted, WPEA proposes a two-tiered SO_2 BACT limit:

- 0.09 lb/MMBtu for coals with greater than or equal to 0.45% sulfur and
- 0.065 lb/MMBtu for coals with less than 0.45% sulfur

WPEA considers BACT to be compliance on a 30-day rolling average basis, however, WPEA agrees to compliance on a 24-hour rolling average basis.

WPEA's proposed SO_2 BACT limits are consistent with the most stringent entries in EPA's RBLC database for facilities using low sulfur western or PRB coal. Table 10.17 discusses all such facilities with BACT limits less than 0.09 lb/MMBtu.

Table 10.17 – Discussion of SO_2 BACT Limits for PC-Fired Boiler Facilities Permitted at Less than 0.09 lb/MMBtu

Facility	State	Emission Limit (lb/MMBtu)	Notes
Deseret Generation & Transmission, Moonlake	UT	0.055	Permitted in 1980. Facility was not constructed. Permit has expired.
City Public Service, Spruce Unit 2	TX	0.06 (1) 0.10 (2)	0.06 lb/MMBtu limit is on annual averaging period. 0.10 lb/MMBtu limit is on same basis as WPEA's proposed 0.09 lb/MMBtu limit. WPEA limit is more stringent.
Desert Rock	Navajo (NM)	0.06	Project will be used to demonstrate the commercial viability and efficiency of an unproven proprietary sorbent injection process/chemical as a means of controlling SO_2 and acid gases.(3) Limit not demonstrated.
Newmont Mining	NV	0.09 for S>0.45 0.065 for S<0.45 (4)	Identical to WPEA's proposed limits.
Arizona Public Service, Cholla Unit 5	AZ	0.072	Facility was not constructed. Limit not demonstrated.

Notes:
(1) Annual average.
(2) 30-day rolling average.
(3) Per the facility's construction permit application dated May 7, 2004.
(4) 24-hour rolling average.

As documented in the table above, none of the facilities with a BACT limit below 0.09 lb/MMBtu (30-day rolling average) has demonstrated compliance via performance testing. Thus, WPEA's proposed limits are lower than any BACT limits currently demonstrated in practice.

Regarding the Desert Rock Energy Center, this facility will utilize an unproven proprietary sorbent injection process/chemical to meet a very low SO_2 BACT limit of 0.06 lb/MMBtu. While previous permit decisions can provide guidance for future BACT determinations, permitting agencies must establish BACT on a case-by-case and facility-by-facility basis. EPA's Draft NSR Manual states the following regarding the basis for BACT limits:

> *Manufacturer's data, engineering estimates and the experience of other sources provide the basis for determining achievable limits. Consequently, in assessing the capability of the control alternative, latitude exists to consider*

> *any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative.*[110]

While WPEA's proposed SO_2 BACT limits would not be the lowest BACT limits ever permitted, the proposed limits represent the maximum degree of reduction for SO_2 at the WPEA PC-fired boilers, taking into account energy, environmental, and economic impacts. The proposed SO_2 BACT limits take into account WPEA's facility-specific boiler size, boiler design, fuel options, and emission controls. The Desert Rock facility will utilize a different design, a different capacity, and a different fuel (coal from the Navajo mine). Since the WPEA Facility is unique in its design, it would be unreasonable to require WPEA to meet an SO_2 BACT limit of 0.06 lb/MMBtu simply because this limit has been permitted for another facility. The U.S. EPA Environmental Appeals Board recently stated agreement with this position:

> *…PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but that those limits must also reflect consideration of any practical difficulties associated with using the control technology.*[111]

WPEA's proposed SO_2 BACT limits are based on careful engineering evaluation, vendor consultation, and consideration of the energy, environmental, and economic impacts as documented above for this unique facility. Thus, WPEA asserts that the proposed SO_2 BACT limits meet the BACT requirement for SO_2 emissions.

As discussed in Section 8.1.10, the dry scrubber system may be inoperative for brief periods during startup due to insufficient flue gas flow rates and/or operating temperatures. During startup and shutdown periods, the boilers will utilize ultra low sulfur distillate fuel and/or low sulfur coal to minimize SO_2 emissions. For startup and shutdown periods when the dry scrubber is not operational, the proposed SO_2 BACT limit is 1.2 lb/MMBtu. Additionally, WPEA will minimize the number of startups that occur each year. Startups are expected to occur approximately 16 times per year per boiler.

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[110] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.24.
[111] PSD Appeal No. 05-04*, In re: Newmont Nevada Energy Investment L.L.C., TS Power Plant*, December 21, 2005, p. 17.

10.5.4 Particulate Matter (PM / PM_{10})

Particulate matter (PM) is the general term for a mixture of solid particles and liquid droplets present in the emissions stream. PM emissions that are less than 10 microns in diameter are referred to as PM_{10}. PM and PM_{10} are emitted from coal-fired boilers as a result of the ash contained in the coal. Ash is the inorganic matter that does not participate in the combustion reactions. Generally, approximately 80% of the ash contained in the coal becomes fly ash and is present in the boiler exhaust as PM and/or PM_{10}.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below. Per EPA's Draft NSR manual, control options incapable of meeting an applicable NSPS would not meet the definition of BACT and are not considered in the BACT analysis.[112]

Lower Emitting Processes/Practices

Lower emitting processes/practices for control of PM/PM_{10} emissions are pre-combustion controls that involve burning coals with a reduced tendency to create PM/PM_{10} emissions. Lower emitting processes/practices include the following:

Coal Selection

In some instances, particulate emissions can be reduced by the substitution of the coal with a coal that has a lower ash content. Combustion of a lower ash-containing coal would result in less fly ash generation, hence, less PM/PM_{10} emissions.

Coal Cleaning

Coal normally contains quantities of inorganic elements such as iron, aluminum, silica, and sulfur. These elements occur primarily in ash-forming mineral deposits embedded within the coal but are also present to a lesser degree within the organic coal structure. Coal cleaning is a process that removes this mineral ash matter from the coal after it is removed from the ground.

The amount of ash, the manner in which it is included in the coal assemblage, and the degree to which it can be removed vary widely with different coals. The application and extent of coal cleaning depends on the particular mine and mining technique. Eastern coals are typically cleaned because Eastern deep mines produce a raw coal product typically containing 25% to 60% ash that cannot be sold without cleaning.[113] Conversely, surface mines tend to employ coal cleaning less often due to the effectiveness of overburden removal and the thickness of the coal seam.

Add-On Controls

Add-on controls identified for PM/PM_{10} emissions reduction are post-combustion controls that operate to remove particulate matter from the exhaust stream. Add-on controls include the following:

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[112] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.12.
[113] Coal information from Energy Ventures Analysis, Inc., July 13, 2006.

Fabric Filter Baghouse

A fabric filter baghouse removes particles and condensed metals (lead, beryllium, mercury, etc.) from the flue gas by drawing dust-laden flue gas and condensables through a bank of filter tubes suspended in a housing. A filter cake, composed of the removed particulate, builds up on the dirty side of the bag. Periodically, the cake is removed through physical mechanisms (e.g., blast of compressed air from the clean side of the bag, mechanical shaking of the bags, etc.) which causes the cake to fall. The dust is then collected in a hopper and removed.

Synthetic fibers are typically used for coal-fired boilers due to the operating temperature and resistivity to chemical attachment. Ryton™ is a felted filter made from polyphenylene sulfide fibers generally attached to a woven polyfluorocarbon backing. These types of bags have been used successfully in coal-fired boiler applications. An alternative bag construction is the use of membranes as is done in Gortex™ bags. The Gortex membrane is an expanded polytetrafluoroethylene (PTFE) membrane that can be laminated over a variety of fibers. These bags are expected to provide slightly higher PM_{10} control efficiency.

Electrostatic Precipitator (ESP)

An electrostatic precipitator (ESP) removes dust or other fine particles from the flue gas by charging the particles inductively with an electric field and then attracting the particles to highly charged collector plates, from which they are removed. An ESP consists of a hopper-bottomed box containing rows of plates forming passages through which the flue gas flows. Centrally located in each passage are emitting electrodes energized with a high-voltage, negative polarity direct current. The voltage applied is high enough to ionize the gas molecules close to the electrodes, resulting in a corona current of gas ions from the emitting electrodes across the gas passages to the grounded collecting plates. When passing through the flue gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The electric field forces the charged particles out of the gas stream towards the grounded plates, and there they collect in a layer. The plates are periodically cleaned by a rapping system to release the ash layer into ash hoppers as an agglomerated mass.

Wet Electrostatic Precipitator (WESP)

A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP: charging, collection, and removal. Unlike with a dry ESP, however, with a WESP, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid, rather than mechanically rapping the collector plates. WESPs are more widely used in applications where the gas stream has a high moisture content, is below the dew point, or includes sticky particulate.

Electro-Catalytic Oxidation (ECO)

ECO is a multi-pollutant control technology under development by Powerspan Corporation. According to the company's website,[114] ECO is a multi-pollutant control technology that simultaneously controls SO_2, NO_X, Hg, and $PM_{2.5}$. The ECO process must be located downstream of a plant's primary particulate removal device (electrostatic precipitator or fabric filter). The ECO technology achieves particulate reduction via a WESP integrated in the tail end of the process.

In 2005, the ECO technology completed a 180-day pilot testing run at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio. The pilot unit processed a flue gas slipstream that represented approximately one-third of the exhaust flow from a 156-MW front wall-fired boiler combusting coal.[115]

The following technologies were omitted from the BACT analysis due to their inability to meet the NSPS Subpart Da PM limit of 0.015 lb/MMBtu[116]:

- Venturi Scrubber
- Wet Scrubber
- Centrifugal Separator (Cyclone)

Step 2 – Eliminate Technically Infeasible Options

The potentially applicable technologies for the control PM/PM_{10} emissions identified in Step 1 were each evaluated for technical feasibility. Technologies that are not commercially available, lack experience in comparable applications, or are not applicable were considered infeasible.

Coal Selection

The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value, each of which strongly affects the design and cost of the boiler and air pollution control equipment. While lower-ash fuels can result in lower particulate loading, coal is not sorted by ash content. Therefore, coal selection is not an available control option, and coal selection is determined to be technically infeasible.

Coal Cleaning

Coal cleaning is a demonstrated technology for reducing the amount of ash present in the coal in some situations. Coal cleaning provides a benefit for coal containing significant overburden or for coals with appreciable pyritic content. However, PRB coal is surface mined from thick coal seams with very little overburden. The PRB coal mining techniques produce a coal product with very little rock and non-combustible material, other than what is bound in the coal. PRB coal contains low

[114] http://www.powerspan.com/technology/scrubber_overview.shtml.
[115] http://www.powerspan.com/technology/scrubber_demonstration.shtml.
[116] 40 CFR §60.42Da(c)(2).

ash levels, typically below 6%.[117] Thus, coal cleaning would provide no significant benefit for the added cost and water consumption. For these reasons, coal cleaning is not typically performed on PRB coal, and WPEA is not aware of any large-scale PRB coal cleaning operations in existence. Additionally, Utah and Colorado coals are not normally cleaned due to the low characteristic ash contents of these coals (typically 8%-11%).[118]

Due to the lack of coal cleaning facilities, there is currently no reliable source of cleaned western coal to supply the WPEA Facility. Since a sufficient supply of cleaned western coal is not available, coal cleaning is determined to be technically infeasible.

Fabric Filter Baghouse

The fabric filter baghouse is a proven technology for the control of boiler PM/PM_{10} emissions. This technology has been widely demonstrated in similar applications and is considered technically feasible.

Electrostatic Precipitator

The ESP is a proven technology for the control of boiler PM/PM_{10} emissions. This technology has been widely demonstrated in similar applications and is considered technically feasible.

Wet Electrostatic Precipitator

The WESP is a proven technology for the control of boiler PM/PM_{10} emissions. This technology has been demonstrated in similar applications and is considered technically feasible.

Electro-Catalytic Oxidation (ECO)

The ECO technology is still in the pilot plant stage of development. To date, the only application of this technology has been a pilot facility processing a flue gas slip stream from a coal-fired boiler.[119] This technology has not been demonstrated for full-scale operations. EPA's Draft NSR Manual states the following regarding technologies in the pilot stage of development:

> *"…technologies in the pilot scale testing stages of development would not be considered available for BACT review."*[120]

Since the ECO technology has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available. Therefore, the ECO technology is determined to be technically infeasible.

[117] USGS CoalQUAL Database, February 2005.
[118] Coal information from Energy Ventures Analysis, Inc., July 13, 2006.
[119] http://www.powerspan.com/technology/scrubber_demonstration.shtml.
[120] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.

In summary, the technically feasible control technologies identified for the control of PM/PM_{10} emissions are:

- Fabric Filter Baghouse
- Electrostatic Precipitator (ESP)
- Wet Electrostatic Precipitator (WESP)

<u>Step 3 – Rank Remaining Control Technologies by Effectiveness</u>

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

<u>Ranking by Control Effectiveness</u>

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. Table 10.18 ranks the feasible PM/PM_{10} control technologies by effectiveness when applied to the Facility.

Table 10.18 – Ranking of PM/PM_{10} Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu) (1)
Fabric Filter Baghouse (with Gortex™ bags or similar)	0.012
Fabric Filter Baghouse (with Ryton™ bags or similar)	0.015
Electrostatic Precipitator	0.015
Wet Electrostatic Precipitator	0.015
PRB Coal or Colorado/Utah Bituminous Coal (baseline)	3.6

Notes:
(1) Control effectiveness values are based on vendor data for a three-hour performance test period.

Based on vendor literature, emission rates of 0.015 lb/MMBtu and 0.012 lb/MMBtu are guaranteed for Ryton™ and Gortex™ bags, respectively. Although fabric filters are typically acknowledged as more effective than ESPs, ESPs are listed at 0.015 lb/MMBtu based on a recent permit (Big Cajun II) and two recent applications (Duke Power – Cliffside and Palatka Generating Station), none of which have been constructed or demonstrated. Additionally, ESPs are not typically utilized in conjunction with a dry SO_2 scrubber due to the better lime utilization achievable with a fabric filter baghouse.

Energy Impacts

This subsection discusses the energy impacts of the remaining PM/PM_{10} control options. One energy impact associated with fabric filter and ESP technology is pressure drop, which increases the energy required to operate the system. Another energy impact is the electric power required to impart an electric charge on the entrained particulate in the ESP. The energy impacts for the PM/PM_{10} control options are presented in Table 10.19.

Table 10.19 – Summary of Energy Impacts for PM/PM_{10} Control Options

Control Option	Typical Pressure Drop (atm) (1)	Power Required to Operate ESP for 3 Units (MW)
Fabric Filter Baghouse (with Gortex™ bags or similar)	0.01 to 0.02	N/A
Fabric Filter Baghouse (with Ryton™ bags or similar)	0.001 to 0.02	N/A
Electrostatic Precipitator	0.001	3.62 (2)
Wet Electrostatic Precipitator	0.001	3.62 (2)

Notes:
(1) Based on EPA Clean Air Technology Center (CATC) control technology factsheets.
(2) Based on a corona power of 800 Watts per 1,000 acfm per the EPA Air Pollution Training *Institute's ESP Design Parameters and Their Effects on Collection Efficiency*.

Environmental Impacts

PM/PM_{10} control devices remove the particulate from the exhaust stream. The primary environmental concern is proper disposal of the particulate collected. The environmental impacts of the remaining PM/PM_{10} control devices are listed in Table 10.20.

Table 10.20 – Summary of Environmental Impacts for PM/PM_{10} Control Options

Control Option	Impact
Fabric Filter Baghouse (with Gortex™ bags or similar)	Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations. Filter bags would be replaced and disposed of as needed.
Fabric Filter Baghouse (with Ryton™ bags or similar)	Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations. Filter bags would be replaced and disposed of as needed.
Electrostatic Precipitator	Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations.
Wet Electrostatic Precipitator	Wastewater stream would have to be treated in accordance with applicable regulations. Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations.

<u>Economic Impacts</u>

An analysis of the economic impacts of the use of Ryton™ bags in comparison to Gortex™ bags is summarized in Table 10.21 below. Additional details of the analysis are presented in Table 10.22. Since fabric filtration has been demonstrated effective in many similar industrial applications, fabric filtration with Ryton-type bags is considered baseline, and the incremental cost of Gortex™ bags is evaluated.

Table 10.21 – Summary of Economic Impacts for PM_{10} Controls for a 530 MW Unit

Control Option	Emissions (tpy)	Control Cost ($/ton)	Total Annualized Cost over Baseline ($/year) [4]	Incremental Cost Effectiveness ($/ton)
Fabric Filter Baghouse (with Gortex™ bags or similar)	274	$25.14 [1]	$1,583,000	$22,942
Fabric Filter Baghouse (with Ryton™ bags or similar)	343	$5.84 [1]	--	--
Electrostatic Precipitator	343	$35 [2]	--	--
Wet Electrostatic Precipitator	343	$48 [3]	--	--
PRB Coal or Colorado/Utah Bituminous Coal – no controls	82,246	--	--	--

Notes:

(1) For comparison, the EPA factsheet for fabric filters (pulse-jet cleaned type) lists the cost effectiveness as $46 to $293 per ton.
(2) Control cost for ESP listed as $35 to $236 per ton in EPA factsheet.
(3) Control cost for WESP listed as $48 to $520 per ton in EPA factsheet.
(4) Emissions baseline considered as 0.015 lb/MMBtu, corresponding to Ryton™ fabric filter and ESP/WESP emission levels.

Table 10.22 – Detail of Economic Impacts for PM_{10} Controls for a 530 MW Unit

	Fabric Filter Baghouse with Ryton™ bags	**Fabric Filter Baghouse with Gortex™ bags**	**Notes**
Capacity, MW	530	530	
Emission Rate, lb/MMBtu	0.015	0.012	
Direct capital costs	$2,222,000	$6,222,000	(1)
Indirect capital costs	$755,000	$2,115,000	(2)
Total Capital Cost	$1,972,000	$5,523,000	
Total capital required, $/kW (net)	$3.70	$10.40	
Annual costs			
Bags and cage replacement	$331,000	$729,000	
Labor	--	$24,000	(3)
Maintenance material	$147,000	$412,000	(4)
Indirects	$89,000	$250,000	(5)
Capital recovery	$231,000	$646,000	
Total annual costs	$478,000	$2,061,000	
Incremental costs	--	$1,583,000	
PM_{10} emissions, tpy	343	274	
Incremental removal, tpy	--	69	
Incremental cost, $/ton	--	$22,942	

Notes:

(1) Includes the bags, cages, installation, and erection.

(2) Includes AFUDC, contingency, engineering, construction and field expenses, startup, and performance tests.

(3) An additional 0.25 man-year of operations and maintenance personnel labor time is assumed for the Gortex bags option for expected more frequent cleaning.

(4) Maintenance material equal to 1% of direct capital costs.

(5) Includes administrative and insurance.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the control technologies are evaluated below, starting with the most effective control.

Fabric Filter Baghouse (with Gortex™ bags or similar)

A case-by-case consideration of energy, environmental, and economic impacts for Gortex™ filter bags is presented below.

Energy Impacts

As discussed in Step 3, the baghouse will require additional auxiliary power to overcome the draft loss across the fabric filter bags. These energy requirements are not significant enough to preclude the use of the baghouse.

Environmental Impacts

As shown in Step 3, there are no major environmental issues that would preclude the use of a baghouse. For the Facility, the collected waste products will be disposed of in an on-site disposal area. The disposal area will be designed, constructed, and permitted in accordance with all applicable regulations.

Economic Impacts

As shown in Step 3, the average cost of controlling PM/PM_{10} with a Gortex™ fabric filter system is $25.14 per ton. While this average cost value is not infeasible, EPA has consistently stated that the economic analysis should evaluate the average cost and the incremental cost.[121] As shown in Table 10.21, the incremental cost for applying Gortex™ bags would be $22,942 per additional ton of PM/PM_{10} removed. This high incremental cost would represent a significant negative economic impact, considering the minimal improvement Gortex™ could provide (i.e., 99.7% removal with Gortex™ vs. 99.6% removal with the next best control). Due to the high incremental cost, Gortex™ filter bags are determined to be infeasible for the WPEA Facility.

Since Gortex™ filter bags are not selected as BACT, the next most effective technology (i.e., Ryton™ filter bags) is evaluated.

Fabric Filter Baghouse (with Ryton™ bags or similar)

A case-by-case consideration of energy, environmental, and economic impacts for Ryton™ filter bags is presented below.

Energy Impacts

As discussed in Step 3, the baghouse will require additional auxiliary power to overcome the draft loss across the fabric filter bags. These energy requirements are not significant enough to preclude the use of the baghouse.

Environmental Impacts

As shown in Step 3, there are no major environmental issues that would preclude the use of a baghouse. For the Facility, the collected waste products will be disposed of in an on-site disposal area. The disposal area will be designed, constructed, and permitted in accordance with all applicable regulations.

[121] Final Order, In Re Inter-Power of New York, Inc., March 16, 1994 and January 19, 2001 Memorandum from John S. Seitz, Director to Air Division Directors, Regions I-X, "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects."

Economic Impacts

As shown in Step 3, the average cost of controlling PM/PM_{10} with a Ryton™ fabric filter system is $5.84 per ton. This economic impact does not preclude the use of Ryton™ filter bags as BACT.

Since this technology presents no significant energy, environmental, or economic impacts, WPEA selects a fabric filter baghouse with Ryton™ (or similar) filter bags as PM/PM_{10} BACT for the PC-fired boilers.

Step 5 – Select BACT

Based on the preceding analysis, BACT for control of boiler PM/PM_{10} emissions is a fabric filter baghouse using Ryton™ or similar type bags with a filterable emissions limit of 0.015 lb/MMBtu on a 3-hour average and 10% opacity on a 6-minute average basis except for one 6-minute period per hour not more than 27% opacity. Continuous compliance with PM/PM_{10} emissions is typically demonstrated by measurement of opacity.

Table 10.76 presents the most stringent opacity limits found in the RBLC and recent permits and permit applications for pulverized coal-fired boiler sources. The most common entry in the table is the NSPS requirement of 20%. Seven recent facilities (Plum Point, Mon Valley, Reliant Energy, Intermountain Power, Sandy Creek, City Public Service, and Longleaf) have permitted limits of 10% opacity. One facility (MidAmerican Energy) has a limit of 5%. No facility in operation has a limit less than 20%.

Two coal-fired facilities were recently permitted with numerical PM/PM_{10} BACT limits less than 0.015 lb/MMBtu. These facilities are listed in Table 10.23.

Table 10.23 – Discussion of PM/PM_{10} BACT Limits for PC-Fired Boiler Facilities Permitted at Less than 0.015 lb/MMBtu

Facility	State	Emission Limit (lb/MMBtu)	Notes
Desert Rock	NM	0.010	Limit is on 24-hour average.
Newmont	NV	0.012	Limit is on 24-hour average.

While these facilities were permitted at less than 0.015 lb/MMBtu with compliance demonstrated through extrapolation of a 3-hour performance test, WPEA would prefer an emission limit suitable for direct comparison with the EPA approved test method for PM/PM_{10}. WPEA proposes to demonstrate compliance with its 0.015 lb/MMBtu BACT limit by conducting a three-hour EPA Method 5 emissions test. WPEA would prefer to compare its PM/PM_{10} BACT limit directly to stack test results instead of projecting a set of three-hour test results into a 24-hour averaging period, which would likely introduce uncertainty into the compliance demonstration. Due to the much shorter averaging period (3-hr for WPEA vs.

24-hr for the other facilities), WPEA is proposing a slightly higher emission rate of 0.015 lb/MMBtu.

Since the fabric filter systems will operate at all times the boilers combust fuel, separate BACT limits are not necessary for startup and shutdown periods.

10.5.5 Volatile Organic Compounds (VOC)

Combustion is a thermal oxidation process in which carbon and hydrogen contained in a fuel combine with oxygen in the combustion zone to form CO_2 and H_2O. VOC emissions are generated during the combustion process as the result of incomplete thermal oxidation of the carbon in the fuel. Properly designed and operated boilers typically emit low levels of VOC. High levels of VOC emissions could result from poor burner design or sub-optimal firing conditions.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below. Per EPA's Draft NSR manual, control options incapable of meeting an applicable NSPS would not meet the definition of BACT and are not considered in the BACT analysis.[122]

Lower Emitting Processes/Practices

Lower emitting processes/practices for VOC emissions control are combustion control techniques that maximize the thermal oxidation of carbon to minimize the formation of VOC. Lower emitting processes/practices include the following:

Combustion Controls

Optimization of the design, operation, and maintenance of the furnace and combustion system is the primary mechanism available for lowering VOC emissions. This process is often referred to as combustion controls. The furnace/combustion system design on modern PC-fired boilers provides all of the factors required to facilitate complete combustion. These factors include continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber. As a result, a properly designed furnace/combustion system is effective at limiting VOC formation by maintaining the optimum furnace temperature and amount of excess oxygen.

Unfortunately, the addition of excess air and maintenance of high combustion temperatures for control of VOC emissions may lead to increased NO_X emissions. Consequently, typical practice is to design the furnace/combustion system (specifically, the air/fuel mixture and furnace temperature) such that VOC emissions are reduced as much as possible without causing NO_X levels to significantly increase.

Proper operation and maintenance of the furnace/combustion system helps to minimize the formation and emission of VOC by ensuring that the furnace/combustion system operates as designed. This includes maintaining the air/fuel ratio at the specified design point, having the proper air and fuel conditions at the burner, and maintaining the fans and dampers in proper working condition.

Add-On Controls

Add-on controls are post-combustion technologies that operate to reduce the level of VOC in the flue gas. Add-on controls include the following:

[122] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.12.

Flares

Flares are commonly used in the control of organic-laden slipstreams from refineries and other chemical manufacturing processes with sufficient heating value. A flare operates by continuously maintaining a pilot flame that is typically maintained by natural gas. When a combustible exhaust stream is vented to a flare, the exhaust stream is ignited by the pilot flame at the flare tip, and combustion occurs in the ambient air above the flare.

Afterburning

Afterburners convert VOC into CO_2 by utilizing simple gas burners to bring the temperature of the exhaust stream up to 1,400 °F to promote complete combustion. Operation of afterburners would require significant amounts of natural gas.

Catalytic Oxidation

A catalytic oxidizer converts the VOC in the combustion gases to CO_2 at temperatures ranging from 500 °F to 700 °F in the presence of a catalyst. Catalytic oxidizers are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst. Catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device; however, this would require reheating the exhaust gases to the required operating temperature for the catalytic process.

External Thermal Oxidation (ETO)

ETO promotes thermal oxidation of the VOC in the flue gas stream in a location external to the boiler. ETO requires heat (1400 °F to 1600 °F) and oxygen to convert VOC in the flue gas to CO_2. There are two general types of ETO that are used for the control of VOC emissions: regenerative thermal oxidization and recuperative thermal oxidization. The primary difference between regenerative and recuperative ETO is that regenerative ETO utilizes a combustion chamber and ceramic heat exchange canisters that are an integral unit, while recuperative ETO utilizes a separate counterflow heat exchanger to preheat incoming air prior to entering the combustion chamber.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable technologies for the control of VOC emissions identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on PC-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[123] A technology that has not been demonstrated on PC-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

[123] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.

Combustion Controls

Combustion controls, which include furnace and combustion system design and proper boiler operation and maintenance, are proven technologies for the reduction of VOC emissions. These technologies have been widely demonstrated in similar applications to generate significantly lower levels of VOC emissions when compared to boilers designed, operated and maintained without regard to VOC emissions.

Based on the proven success of this control strategy, combustion controls are considered a demonstrated technology for PC-fired boiler VOC emissions control. Therefore, combustion controls are considered technically feasible.

Flares

Flares are commonly used in the control of organic slipstreams from refineries and other chemical manufacturing processes with sufficient heating value. Flares have not been demonstrated for PC-fired boiler VOC emission control. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

Limitations on the scalability of this technology preclude its commercial availability. For example, the maximum exhaust flow rate for commercially available flares is approximately 1.06 MMscfm,[124] while the flow rate for each PC-fired boiler at the Facility is 1.28 MMscfm (i.e., over 20% higher than commercially available). Therefore, flares are not considered an available control technology for this application. Furthermore, the heating value of the PC-boiler exhaust is essentially zero, far below the practical operating range for flares (i.e., 300 Btu/scf).[125] Since the PC-fired boiler exhaust will not have sufficient heating value for flaring and since flares have not been applied for PC-fired boiler emissions control, flares are not considered an applicable technology for PC-fired boilers.

As discussed in this section, flares are not available or applicable for PC-fired boiler VOC emissions control. Therefore, flares are determined to be technically infeasible for PC-fired boilers.

Afterburners

Based on a review of the RBLC database and a survey of air permits for coal-fired power plants, afterburners are not demonstrated for PC-fired boiler VOC control. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

The term "afterburner" is generally appropriate only to describe a thermal oxidizer used to control gases coming from a process where combustion is incomplete.[126]

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[124] U.S. EPA, document no. EPA-452/F-03-019: *Air Pollution Control Technology Fact Sheet - Flares*, p. 1.
[125] U.S. EPA, document no. EPA-452/F-03-019: *Air Pollution Control Technology Fact Sheet - Flares*, p. 2.
[126] U.S. EPA, document no. EPA-452/F-03-022: *Air Pollution Control Technology Fact Sheet - Thermal Incinerator*, p. 1.

Since the PC-fired boilers will be carefully tuned to maximize fuel combustion efficiency (i.e., subsequently minimizing VOC emissions) while minimizing NO_X formation, the process will result in essentially complete combustion. Therefore, additional afterburner combustion would not be expected to provide any useful benefit, and afterburners are determined to be not applicable for PC-fired boiler VOC emissions control.

Since afterburners are not applicable for PC-fired boiler VOC emissions control, afterburners are determined to be technically infeasible.

<u>Catalytic Oxidation</u>

Catalytic oxidizers are typically installed to remove VOC, CO, and organic HAP emissions from exhaust streams in the following equipment/processes:

- Surface coating and printing operations;
- Varnish cookers;
- Foundry core ovens;
- Filter paper processing ovens;
- Plywood veneer dryers;
- Gasoline bulk loading stations;
- Chemical process vents;
- Rubber products and polymer manufacturing; and
- Polyethylene, polystyrene, and polyester resin manufacturing.[127]

In a number of cases, catalytic oxidation has been used to control VOC emissions from natural gas-fired combustion turbines since oxidation catalysts are suitable for gas streams with negligible particulate loading. However, catalytic oxidation is not a demonstrated technology for PC-fired boilers. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

Several factors render VOC catalytic oxidation not applicable for PC-fired boilers. First, catalytic oxidation systems require a minimum temperature of 500 °F for proper operation, which would dictate that the catalyst be installed upstream of the flue gas desulfurization and fabric filter systems. The particulate loading of the flue gas stream upstream of the fabric filter would be higher than the design capacity of any oxidation catalyst. In addition, trace elements present in coal and the resulting combustion gases (e.g., chlorine and sulfur in particular[128]) would foul an oxidation catalyst and dramatically reduce its effectiveness. Furthermore, SO_2 in the flue gas stream could be oxidized to form SO_3, which could react with the moisture in the flue gas to form sulfuric acid and create a corrosive environment. Alternatively, the SO_3 could convert to NH_4HSO_4 salts that would foul the air preheater. For these reasons, VOC catalytic oxidation is not an applicable technology for PC-fired boilers.

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[127] U.S. EPA, document no. EPA-452/F-03-018: *Air Pollution Control Technology Fact Sheet - Catalytic Incinerator*, p. 3.
[128] Ibid.

Additionally, catalytic oxidation is not an available technology for PC-fired boiler VOC emissions control. This technology is not considered commercially available since it has not been demonstrated for PC-fired boilers or similar exhaust streams and since commercially produced package incinerators are not available for exhaust streams with comparable size and composition. For example, typical commercially available package catalytic oxidizers can handle exhaust gas flow rates of up to 0.05 MMscfm,[129] while each PC-fired boiler will have an exhaust flow rate of 1.28 MMscfm, far above the commercially available range for package units. For these reasons, VOC catalytic oxidation is not an available technology for PC-fired boilers.

As discussed in this section, catalytic oxidation is not available or applicable for PC-fired boiler VOC emissions control. Therefore, catalytic oxidation is determined to be technically infeasible for PC-fired boilers.

External Thermal Oxidation (ETO)

ETO is generally utilized for controlling VOC, CO, or organic HAP emissions from high-concentration, non-combustion sources (e.g., surface coating operations and chemical plants). Regenerative ETO and recuperative ETO have not been demonstrated for use on PC-fired utility plants. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

ETO is not applicable for PC-fired boiler VOC control for the same reason as afterburners. Since the PC-fired boilers will be carefully tuned to maximize fuel combustion efficiency (i.e., subsequently minimizing VOC emissions) while minimizing NO_X formation, the process will result in essentially complete combustion. Therefore, additional ETO combustion would not be expected to provide any useful benefit (i.e., the PC-fired boiler serves as a thermal oxidizer where high combustion efficiency is a primary concern), and ETO is determined to be not applicable.

Additionally, the regenerative and recuperative ETO heat exchange systems would be vulnerable to the same sulfur concerns as discussed for VOC catalytic oxidation above. SO_2 in the flue gas stream could be oxidized to form SO_3, which could react with the moisture in the flue gas to form sulfuric acid and create a corrosive environment. Alternatively, the SO_3 could convert to NH_4HSO_4 salts that would foul the air preheater.

For the reasons discussed above, ETO is not applicable for PC-fired boiler VOC emissions control. Therefore, ETO is determined to be technically infeasible.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

[129] U.S. EPA, document no. EPA-452/F-03-018: *Air Pollution Control Technology Fact Sheet - Catalytic Incinerator*, p. 3.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, combustion controls are the only remaining feasible control technology. Table 10.24 ranks the feasible VOC control technologies by effectiveness when applied to the Facility.

Table 10.24 - Ranking of VOC Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu)
Combustion Controls	0.0036 (1)

Notes:
(1) Based on engineering estimates.

Energy Impacts

Combustion controls are an integral part of the combustion process and are designed to maximize combustion efficiency while maintaining optimal VOC and NO_X emissions performance. Thus, combustion controls do not create any energy impacts.

Environmental Impacts

Since maximum fuel combustion efficiency (i.e., minimum VOC formation) occurs at the high end of the combustion temperature range, there is a potential for increased NO_X emissions due to thermal NO_X formation. Since NO_X formation is a concern, combustion controls are designed and operated to minimize VOC and NO_X formation while maximizing combustion efficiency. Thus, combustion controls do not create any significant environmental impacts.

Economic Impacts

Combustion controls are part of the standard design of modern PC-fired boilers and do not create any economic impacts.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of combustion controls are evaluated below.

Energy Impacts

There are no energy impacts that preclude the selection of combustion controls as VOC BACT.

Environmental Impacts

As discussed in Step 3, combustion controls are designed to minimize VOC emissions while maintaining an appropriate balance with NO_X formation. There are no environmental impacts that preclude the selection of combustion controls as VOC BACT.

Economic Impacts

There are no economic impacts that preclude the selection of combustion controls as VOC BACT.

Since there are no energy, environmental, or economic impacts that preclude the use of combustion controls, this technology is selected as VOC BACT for the PC-fired boilers.

Step 5 – Select BACT

Based on the analysis presented above, BACT for VOC emissions control is the application of combustion controls. The proposed BACT emission limit is 0.0036 lb/MMBtu on a 3-hour average basis. As shown in Table 10.78, all comparable units with lower VOC BACT limits have either not been constructed or are permitted for higher NO_X emissions than the WPEA Facility.

Combustion controls will be operated at all times the boilers combust fuel. During periods of startup and shutdown, the boilers may produce higher uncontrolled emissions due to less stable combustion conditions. During startup and shutdown periods, WPEA will utilize combustion controls as BACT with a VOC BACT limit of 0.01 lb/MMBtu. Additionally, WPEA will minimize the number of startups that occur each year. Startups are expected to occur approximately 16 times per year per boiler.

10.5.6 Lead (Pb)

Lead (Pb) is a naturally-occurring element found in the Earth's crust. As a natural fuel extracted from the Earth's crust, coal contains trace levels of lead. During the coal combustion process, lead may be vaporized and later condensed or adsorbed by fly ash suspended in the flue gas. In a PC-boiler exhaust stream, lead is typically contained in the particulate matter with size less than 10 microns. Thus, the control technologies available for the control of lead emissions are the same technologies available for the control of particulate matter.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

The lower emitting processes/practices for control of lead emissions are pre-combustion controls that involve burning coals with a reduced lead content. The lower emitting processes/practices include the following:

Coal Selection

Lead exists in trace amounts in coal deposits. The amount of lead varies among coal ranks and among the seams within a given rank. Lead emissions could be reduced by burning coals that contained less lead content.

Coal Cleaning

Coal normally contains quantities of inorganic elements such as iron, aluminum, silica, sulfur, and trace levels of lead. These elements may occur in the ash-forming mineral deposits embedded within the coal or within the organic coal structure itself. Coal cleaning is a process that removes this mineral ash matter from the coal after it is removed from the ground.

The amount of ash, the manner in which it is included in the coal assemblage, and the degree to which it can be removed vary widely with different coals. The application and extent of coal cleaning depends on the particular mine and mining technique. Eastern coals are typically cleaned because Eastern deep mines produce a raw coal product typically containing 25% to 60% ash that cannot be sold without cleaning.[130] Conversely, surface mines tend to employ coal cleaning less often due to the effectiveness of overburden removal and the thickness of the coal seam.

Add-On Controls

Add-on controls identified for lead emissions reduction are post-combustion controls that operate to remove lead-containing particulate matter from the exhaust stream. Add-on controls include the following:

[130] Coal information from Energy Ventures Analysis, Inc., July 13, 2006.

Fabric Filter Baghouse

A fabric filter baghouse removes particles and condensed metals (including lead) from the flue gas by drawing dust-laden flue gas and condensables through a bank of filter tubes suspended in a housing. A filter cake, composed of the removed particulate, builds up on the dirty side of the bag. Periodically, the cake is removed through physical mechanisms (e.g., blast of compressed air from the clean side of the bag, mechanical shaking of the bags, etc.) which causes the cake to fall. The dust is then collected in a hopper and removed.

Electrostatic Precipitator (ESP)

An electrostatic precipitator (ESP) removes dust and condensed metals (including lead) from the flue gas by charging the particles inductively with an electric field and then attracting the particles to highly charged collector plates, from which they are removed. An ESP consists of a hopper-bottomed box containing rows of plates forming passages through which the flue gas flows. Centrally located in each passage are emitting electrodes energized with a high-voltage, negative polarity direct current. The voltage applied is high enough to ionize the gas molecules close to the electrodes, resulting in a corona current of gas ions from the emitting electrodes across the gas passages to the grounded collecting plates. When passing through the flue gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The electric field forces the charged particles out of the gas stream towards the grounded plates, and there they collect in a layer. The plates are periodically cleaned by a rapping system to release the ash layer into ash hoppers as an agglomerated mass.

Wet Electrostatic Precipitator (WESP)

A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP: charging, collection, and removal. Unlike with a dry ESP, however, with a WESP, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid, rather than mechanically rapping the collector plates. WESPs are more widely used in applications where the gas stream has a high moisture content, is below the dew point, or includes sticky particulate.

Wet Scrubber

Wet scrubbers achieve lead-containing particulate removal through liquid-to-gas contact. In a spray tower scrubber, the particulate-laden stream is introduced into a chamber where it contacts the liquid droplets generated by the spray nozzles. Particulate removal is accomplished via physical absorption of the particles into the liquid droplets. The size of the droplets generated by the spray nozzles is controlled to maximize liquid-particle contact and, consequently, scrubber collection efficiency.[131]

[131] U.S. EPA, document no. EPA-452/F-03-016: *Air Pollution Control Technology Fact Sheet – Spray-Chamber/Spray-Tower Wet Scrubber*, p. 3.

Venturi Scrubber

In a venturi scrubber, lead-containing, dust-laden gases are wetted continuously at the venturi throat. Flowing at 12,000 to 18,000 feet per minute, the high-velocity gases produce a shearing force on the scrubbing liquid due to the initial high velocity differential between the two steams. This shearing force causes the liquid to become atomized into very fine droplets. Impaction takes place between the dust entrained in the gas stream and the liquid droplets. As the gas decelerates, collision continues and agglomerated dust-laden liquor droplets discharge through a diffuser into the lower chamber of a separator vessel. Impingement of the stream into the liquid reservoir removes most of the particulate.

Centrifugal Separator (Cyclone)

The centrifugal separator, or cyclone separator, achieves lead-containing particulate removal by centrifugal, inertial, and gravitational forces developed in a vortex separator. The dust-laden gas is admitted either tangentially or axially over whirl vanes to create a high velocity in the cylindrical portion of the device. Particles are subjected to a centrifugal force and an opposing viscous drag. The balance between these two forces determines whether a particle will move to the wall or be carried into the vortex sink and be passed on to the clean-gas outlet tube. Because these collectors depend primarily on differential inertia, collection efficiencies vary with particle size. Efficiencies can be high on materials greater than 20 µm in size but drop off rapidly for smaller particles. Due to their efficiency in removing coarse particles, the modern-day use of a cyclone is typically limited to first-stage particulate removal for stoker-fired and fluidized-bed boilers, which produce a large amount of coarse particles as compared to pulverized coal boilers.

Electro-Catalytic Oxidation (ECO)

ECO is a multi-pollutant control technology under development by Powerspan Corporation. According to the company's website,[132] ECO is a multi-pollutant control technology that simultaneously controls SO_2, NO_X, Hg, and $PM_{2.5}$. The ECO process must be located downstream of a plant's primary particulate removal device (electrostatic precipitator or fabric filter). The ECO technology achieves particulate reduction via a WESP integrated in the tail end of the process. Although the company does not claim that ECO removes lead, some degree of lead removal is assumed to be associated with particulate removal by the system.

In 2005, the ECO technology completed a 180-day pilot testing run at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio. The pilot unit processed a flue gas slipstream that represented approximately one-third of the exhaust flow from a 156-MW front wall-fired boiler combusting coal.[133]

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[132] http://www.powerspan.com/technology/scrubber_overview.shtml.
[133] http://www.powerspan.com/technology/scrubber_demonstration.shtml.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable lead control technologies identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on PC-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[134] A technology that has not been demonstrated on PC-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Coal Selection

The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value, each of which strongly affects the design and cost of the boiler and air pollution control equipment. While lower-ash fuels can result in lower particulate loading and therefore lower potential lead emissions, coal is not sorted by ash content. Therefore, coal selection is not an available control option, and coal selection is determined to be technically infeasible.

Coal Cleaning

Coal cleaning is a demonstrated technology for reducing the amount of ash and therefore the amount of lead present in coal in some situations. Coal cleaning provides a benefit for coal containing significant overburden or for coals with appreciable pyritic content. However, PRB coal is surface mined from thick coal seams with very little overburden. The PRB coal mining techniques produce a coal product with very little rock and non-combustible material, other than what is bound in the coal. PRB coal contains low ash levels, typically below 6%.[135] Thus, coal cleaning would provide no significant benefit for the added cost and water consumption. For these reasons, coal cleaning is not typically performed on PRB coal, and WPEA is not aware of any large-scale PRB coal cleaning operations in existence. Additionally, Utah and Colorado coals are not normally cleaned due to the low characteristic ash contents of these coals (typically 8%-11%).[136]

Due to the lack of coal cleaning facilities, there is currently no reliable source of cleaned western coal to supply the WPEA Facility. Since a sufficient supply of cleaned western coal is not available, coal cleaning is determined to be technically infeasible.

Fabric Filter Baghouse

The fabric filter baghouse is a proven technology for the control of boiler lead emissions. This technology has been widely demonstrated in similar applications and is considered technically feasible.

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134 U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.
135 USGS CoalQUAL Database, February 2005.
136 Coal information from Energy Ventures Analysis, Inc., July 13, 2006.

Electrostatic Precipitator

The ESP is a proven technology for the control of boiler lead emissions. This technology has been widely demonstrated in similar applications and is considered technically feasible.

Wet Electrostatic Precipitator

The WESP is a proven technology for the control of boiler lead emissions. This technology has been demonstrated in similar applications and is considered technically feasible.

Wet Scrubber

Wet scrubbers are a proven technology for the control of particulate and therefore lead emissions. Wet scrubbers have been demonstrated and are considered technically feasible.

Venturi Scrubber

Venturi scrubbers are a proven technology for the control of particulate and therefore lead emissions. Venturi scrubbers have been demonstrated and are considered technically feasible.

Centrifugal Separator (Cyclone)

Cyclones are a proven technology for the control of particulate and therefore lead emissions. Cyclones have been demonstrated and are considered technically feasible.

Electro-Catalytic Oxidation (ECO)

The ECO technology is still in the pilot plant stage of development. To date, the only application of this technology has been a pilot facility processing a flue gas slip stream from a coal-fired boiler.[137] This technology has not been demonstrated for full-scale operations. EPA's Draft NSR Manual states the following regarding technologies in the pilot stage of development:

> *"…technologies in the pilot scale testing stages of development would not be considered available for BACT review."*[138]

Since the ECO technology has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available. Therefore, the ECO technology is determined to be technically infeasible.

In summary, the following lead control technologies are technically feasible:

- Fabric Filter Baghouse
- Electrostatic Precipitator (ESP)

[137] http://www.powerspan.com/technology/scrubber_demonstration.shtml.
[138] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.

- Wet Electrostatic Precipitator (WESP)
- Wet Scrubber
- Venturi Scrubber
- Centrifugal Separator (Cyclone)

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. Table 10.25 ranks the feasible lead control technologies by effectiveness when applied to the Facility.

Table 10.25 – Ranking of Lead Control Technologies by Effectiveness

Control Technology	Control Efficiency (%)	Control Effectiveness (lb/MMBtu) (1)
Fabric Filter Baghouse	99%	1.8×10^{-5}
Electrostatic Precipitator	99%	1.8×10^{-5}
Wet Electrostatic Precipitator	99%	1.8×10^{-5}
Venturi Scrubber	95%	9.0×10^{-5}
Wet Scrubber	95%	9.0×10^{-5}
Centrifugal Separator	95%	9.0×10^{-5}
Fuel Selection	Baseline	1.8×10^{-3}

Notes:
(1) Based on COALQUAL database information and estimated/reported control efficiency values.

The lead emission rate for a coal-fired boiler depends on the lead content of the coal. The COALQUAL database developed by the USGS was reviewed to determine the possible lead contents for PRB coal. For PRB coal, lead content is in the range of less than 1 ppm to 55 ppm, with an average of 4.42 ppm. Based on the average lead content plus two standard deviations, the estimated lead emission rate, without add-on controls, is 1.8×10^{-3} lb/MMBtu. (Using the same methodology, the expected lead emission rate for firing exclusively Colorado/Utah bituminous coal would be slightly lower, 1.3×10^{-3}.)

Table 10.79 at the end of this Appendix lists the lead emission limits that were found for pulverized coal-fired boilers from a review of the RBLC database and recent permits and permit applications. In some cases, the control efficiency and control technology were not identified. The highest reported control efficiency was 99%. Flue gas desulfurization (FGD) systems and/or particulate matter control devices were identified as the only control technologies.

Quantitative information regarding the lead removal effectiveness of particulate matter control devices is not readily available. A control device that can reportedly capture 95% of particulate matter may not capture 95% of lead. For the purpose of this evaluation, the lead removal effectiveness was assumed equal to the particulate matter removal effectiveness at the lower end of the reported range.

Energy Impacts

This subsection lists the energy impacts of the remaining lead control options. One energy impact associated each technologies is pressure drop, which increases the energy required to operate the system. For the ESP technologies, another energy impact is the electric power required to impart an electric charge on the entrained particulate. The energy impacts for the lead control options are presented in Table 10.26.

Table 10.26 – Summary of Energy Impacts for Lead Control Options

Control Option	Typical Pressure Drop (atm) (1)	Power Required to Operate ESP for 3 Units (MW)
Fabric Filter Baghouse	0.01 to 0.02 (1)	N/A
Electrostatic Precipitator	0.001 (1)	3.62 (2)
Wet Electrostatic Precipitator	0.001 (1)	3.62 (2)
Wet Scrubber	0.004 (3)	N/A
Venturi Scrubber	0.02 (4)	N/A
Centrifugal Separator (Cyclone)	0.005 (1)	N/A

Notes:

(1) Based on EPA Clean Air Technology Center (CATC) control technology factsheets.

(2) Based on a corona power of 800 Watts per 1,000 acfm per the EPA Air Pollution Training *Institute's ESP Design Parameters and Their Effects on Collection Efficiency*.

(3) Typical pressure drop obtained from Utah Department of Environmental Quality Intent to Approve No. DAQE-IN1743011-06, May 9, 2006.

(4) Typical minimum pressure drop based on vendor data.

Environmental Impacts

Lead control devices remove the particulate from the exhaust stream. One environmental concern is proper disposal of the particulate collected. Another concern for the wet technologies is the wastewater created by the control device. The environmental impacts of the remaining lead control devices are listed in Table 10.27.

Table 10.27 – Summary of Environmental Impacts for Lead Control Options

Control Option	Impact
Fabric Filter Baghouse	Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations. Filter bags would be replaced and disposed of as needed.
Electrostatic Precipitator	Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations.
Wet Electrostatic Precipitator	Wastewater stream would have to be treated in accordance with applicable regulations. Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations.
Wet Scrubber	Wastewater stream would have to be treated in accordance with applicable regulations. Collected waste products would have to be removed and disposed of in accordance with applicable regulations.
Venturi Scrubber	Wastewater stream would have to be treated in accordance with applicable regulations. Collected waste products would have to be removed and disposed of in accordance with applicable regulations.
Centrifugal Separator (Cyclone)	Collected waste products would have to be removed and disposed of in accordance with applicable regulations.

Economic Impacts

Due to the low uncontrolled levels of lead in the exhaust and uncertainties surrounding the lead capture efficiencies of the various technologies, accurate economic impact estimates would be difficult to obtain. Since WPEA is not proposing to eliminate any control technology on the basis of cost, the economic impacts for lead ($/ton) are not presented here.[139]

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the control technologies are evaluated below, starting with the most effective control. A fabric filter baghouse is considered the top control option since it achieves the lowest available lead emission rate and

[139] However, Table 10.21 presents the relative costs for the more effective lead control technologies (i.e., fabric filter and ESP technologies).

since other options achieving the same emission rate do not achieve better energy or environmental performance as documented in Step 3.

Fabric Filter Baghouse

A case-by-case consideration of energy, environmental, and economic impacts for a fabric filter baghouse is presented below.

Energy Impacts

As discussed in Step 3, a fabric filter baghouse will require a nominal amount of additional auxiliary power to overcome the draft loss across the fabric filter bags. These energy requirements are not significant enough to preclude the use of a baghouse.

Environmental Impacts

As shown in Step 3, there are no major environmental issues that would preclude the use of a baghouse. For the Facility, the collected waste products will be disposed of in an on-site disposal area. The disposal area will be designed, constructed, and permitted in accordance with all applicable regulations.

Economic Impacts

There are no economic impacts that would preclude the use of a fabric filter baghouse as BACT.

Since this technology presents no significant energy, environmental, or economic impacts, WPEA selects a fabric filter baghouse as BACT for lead emissions from the PC-fired boilers.

Step 5 – Select BACT

Based on the preceding analysis, BACT for control of PC-boiler lead emissions is a fabric filter baghouse. The BACT emissions limit for lead is proposed to be 1.8 x 10^{-5} lb/MMBtu on a 3-hour rolling average basis.

Since the fabric filter systems will operate at all times the boilers combust fuel, separate BACT limits are not necessary for startup and shutdown periods.

10.5.7 Fluorides

Fluorides are emitted from coal-fired boilers due to trace concentrations of elemental fluorine and fluorine compounds in the coal. Fluorine is emitted predominantly in the gaseous form of hydrogen fluoride (HF). Hydrogen fluoride is an acid gas and can be controlled by the same technologies available for SO_2 emissions. For the purposes of this analysis, fluorides are expressed as HF as appropriate since all emissions of fluorides from the PC boilers are expected to be in the form of HF.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

The lower emitting processes/practices for control of HF emissions are pre-combustion controls that involve burning coals with a reduced fluorine content. The lower emitting processes/practices include the following:

Coal Selection

Fluorine exists in trace amounts in coal deposits. The amount of fluorine varies among coal ranks and among the seams within a given rank. Fluoride emissions could be reduced by burning coals that contained less fluorine content.

Coal Cleaning

Coal normally contains quantities of inorganic elements such as iron, aluminum, silica, sulfur, and trace levels of fluorine. These elements may occur in the ash-forming mineral deposits embedded within the coal or within the organic coal structure itself. Coal cleaning is a process that removes this mineral ash matter from the coal after it is removed from the ground.

The amount of ash, the manner in which it is included in the coal assemblage, and the degree to which it can be removed vary widely with different coals. The application and extent of coal cleaning depends on the particular mine and mining technique. Eastern coals are typically cleaned because Eastern deep mines produce a raw coal product typically containing 25% to 60% ash that cannot be sold without cleaning.[140] Conversely, surface mines tend to employ coal cleaning less often due to the effectiveness of overburden removal and the thickness of the coal seam.

Add-On Controls

Some of the add-on controls described in the SO_2 BACT analysis also tend to control HF emissions. These add-on controls include the following:

[140] Coal information from Energy Ventures Analysis, Inc., July 13, 2006.

Wet Scrubber

The wet scrubber is a once-through wet technology. In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The HF is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport/disposal.

The wet scrubber can be further classified on the basis of the reagents used and the by-products generated. The typical reagents are lime and limestone. Additives, such as magnesium, may be added to the lime or limestone to increase the reactivity of the reagent. Seawater has also been used as a reagent since it has a high concentration of dissolved limestone. The reaction by-products are calcium sulfite and/or calcium sulfate. The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced depending on the desired by-product. The most common wet scrubber application utilizes limestone as the reagent and forced oxidation of the reaction by-products to form calcium sulfate.

Regenerable Wet Scrubber

The regenerable wet scrubber is a regenerable wet technology that uses sodium sulfite, magnesium oxide, sodium carbonate, amine, or ammonia as the sorbent for removal of HF from the flue gas. The spent sorbent is regenerated as needed to maintain effectiveness. Regenerable wet scrubbers achieve an HF emissions reduction equivalent to that of a non-regenerable wet scrubber.

Spray Dryer Absorber (Dry Scrubber)

The dry scrubber is a once-through dry technology. In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The HF is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a dry form upon leaving the system and are subsequently captured in a downstream particulate collection device, typically a fabric filter baghouse.

Circulating Dry Scrubber (CDS)

The CDS is a once-through dry technology. In a CDS, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and HF. The by-products leave the absorber in a dry form with the flue gas and are subsequently captured in a downstream particulate collection device.

Limestone Injection Dry Scrubbing (LIDS)

The LIDS technology combines furnace sorbent injection (FSI) and dry scrubber technologies. In the LIDS system, limestone is injected into the furnace and a spray dryer absorber is installed between the air heater and particulate collection device. The reagent used in the spray dryer is a hydrated reaction by-product recycled from the particulate collection device.

Duct Sorbent Injection (DSI)

DSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb HF. In the DSI technology, the reagent is injected into the ductwork between the air heater and particulate collection device.

While DSI could presumably be used in conjunction with a wet scrubber, there is no data available to indicate a combined DSI + wet scrubber system would remove HF more effectively than either technology alone. Therefore, DSI + wet scrubber is not evaluated as a separate control option.

DSI is not evaluated in conjunction with a dry scrubber as DSI would likely interfere with the operation of a dry scrubber. (DSI systems require humidification of the flue gas to a close approach to the adiabatic saturation temperature.[141] Thus, installing a DSI system in conjunction with a dry scrubber would interfere with the ability of the dry scrubber to evaporate the moisture in the reagent slurry and function properly.)

Furnace Sorbent Injection (FSI)

FSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb HF. In the FSI technology, the reagent is injected directly into the furnace and the reaction product is collected in the downstream particulate collection device.

While FSI could presumably be used in conjunction with a wet scrubber, there is no data available to indicate a combined FSI + wet scrubber system would remove HF more effectively than either of the technologies alone. Therefore, FSI is not evaluated in conjunction with a wet scrubber.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable HF control technologies identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on PC-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[142] A technology that has not been demonstrated on PC-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Coal Selection

The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value, each of which strongly affects the design and cost of the boiler and air pollution control equipment. While lower-fluorine fuels could result in lower potential HF emissions, coal is not sorted by fluorine content.

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[141] Nolan, Paul S., The Babcock & Wilcox Company, *Flue Gas Desulfurization Technologies for Coal-Fired Power Plants,* Presented at the Coal-Tech 2000 International Conference.
[142] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.

Therefore, coal selection is not an available control option, and coal selection is determined to be technically infeasible.

Coal Cleaning

Coal cleaning is a demonstrated technology for reducing the amount of ash and therefore the amount of trace elements (e.g., fluorine) present in coal in some situations. Coal cleaning provides a benefit for coal containing significant overburden or for coals with appreciable pyritic content. However, PRB coal is surface mined from thick coal seams with very little overburden. The PRB coal mining techniques produce a coal product with very little rock and non-combustible material, other than what is bound in the coal. PRB coal contains low ash levels, typically below 6%.[143] Thus, coal cleaning would provide no significant benefit for the added cost and water consumption. For these reasons, coal cleaning is not typically performed on PRB coal, and WPEA is not aware of any large-scale PRB coal cleaning operations in existence. Additionally, Utah and Colorado coals are not normally cleaned due to the low characteristic ash contents of these coals (typically 8%-11%).[144]

Due to the lack of coal cleaning facilities, there is currently no reliable source of cleaned western coal to supply the WPEA Facility. Since a sufficient supply of cleaned western coal is not available, coal cleaning is determined to be technically infeasible.

Wet Scrubber

Wet scrubbers have been installed and operated successfully on PC boilers. Thus, wet scrubbers are considered technically feasible.

Regenerable Wet Scrubber

Regenerable wet scrubbers have been installed and operated successfully on PC boilers. Thus, regenerable wet scrubbers are considered technically feasible.

Spray Dryer Absorber (Dry Scrubber)

Dry scrubbers have been installed and operated successfully on PC boilers. Thus, dry scrubbers are considered technically feasible.

Circulating Dry Scrubber (CDS)

CDS have only been domestically applied to two smaller coal-fired boilers: the 80-MW Neil Simpson Unit 2 and the 50-MW[145] LG&E Roanoke Valley Unit 2, both of which have experienced problems with lime utilization and corrosion.[146] CDS have not been demonstrated at the 530-MW scale of the WPEA Facility. Therefore, an

143 USGS CoalQUAL Database, February 2005.
144 Coal information from Energy Ventures Analysis, Inc., July 13, 2006.
145 Capacity from Powergen: http://www.pwrgen.com/DB_Hist/Projects_2.asp.
146 Supplemental BACT information provided by WYGEN to the Wyoming Department of Environmental Quality, July 1, 2002.

assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible. Regarding availability, EPA's Draft NSR Manual states the following:

> *"Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available..."*[147]

The size and scale differences between a 50-MW or 80-MW unit and a 530-MW unit would require significant design, testing, and modeling to evaluate the feasibility of scaling up CDS to the size of WPEA's proposed project. Scale-up efforts for fluidized bed systems are known to be particularly problematic and would be expected to require a significant level of effort and cost. Since the only demonstrated applications of the CDS technology have been on boilers approximately one-seventh the size of the WPEA boilers, CDS are not considered to have been applied to full-scale operations. Therefore, CDS are not considered available. Consequently, CDS are considered technically infeasible in accordance with EPA's Draft NSR Manual.

Limestone Injection Dry Scrubbing (LIDS)

LIDS is not a demonstrated technology for controlling HF emissions from large-scale coal combustion. The LIDS technology is still undergoing significant research and development aimed at improving performance and increasing the scale of application.[148] Per EPA's Draft NSR Manual, technologies that have not yet been applied to full-scale operations are not considered available.[149] Since LIDS is still under development and is not commercially available for large-scale operations, this technology is not considered available. Consequently, the LIDS technology is determined to be technically infeasible.

Duct Sorbent Injection (DSI)

Although there is little operating experience supporting the effectiveness of DSI in removing HF from PC-fired boiler exhaust, DSI is considered technically feasible.

Furnace Sorbent Injection (FSI)

Although there is little operating experience supporting the effectiveness of FSI in removing HF from PC-fired boiler exhaust, FSI is considered technically feasible.

In summary, the technically feasible control technologies identified for the control of HF emissions are:

- Wet Scrubber
- Regenerable Wet Scrubber
- Dry Scrubber
- Duct Sorbent Injection (DSI)
- Furnace Sorbent Injection (FSI)

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[147] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.11.
[148] Nolan, Paul S., The Babcock & Wilcox Company, *Flue Gas Desulfurization Technologies for Coal-Fired Power Plants,* Presented at the Coal-Tech 2000 International Conference.
[149] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.11.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. Table 10.28 ranks the feasible fluorides control technologies by effectiveness when applied to the Facility.

Table 10.28 – Ranking of Fluorides Control Technologies by Effectiveness

Control Technology	Control Efficiency	Emission Rate as HF (lb/MMBtu)
Dry Scrubber	95% (1)	9.7×10^{-4}
Wet Scrubber (once-through or regenerable)	44% (2)	0.011
Duct Sorbent Injection (DSI)	0% to 90% (3)	--
Furnace Sorbent Injection (FSI)	0% to 90% (3)	--
Baseline	--	0.019 (4)

Notes:
(1) Dry scrubber control efficiency based data from EPA Document No. OAR-2002-0056-5736.
(2) Wet scrubber control efficiency based data from EPA Document No. OAR-2002-0056-5736.
(3) Very little literature exists on the HF reduction for either type of sorbent injection. A DOE-NETL test report did not measure any removal while some vendor literature claims over 90%.
(4) Based on PRB coal F content as HF from USGS COALQUAL database.

Technical publications, vendor information, permits and permit applications, and the RBLC database were reviewed to determine the range of reported control efficiencies for each of the technically feasible HF control technologies identified in Step 2. Very little information was found with regard to control of fluorine and HF emissions as compared to what is available for other pollutants, such as SO_2 and NO_X.

The level of HF emissions from a coal-fired boiler depends on the fluorine content of the coal. The COALQUAL database developed by the USGS was reviewed to determine the possible fluorine contents for PRB coal. Fluorine content of PRB coal ranges from 14 ppm to 430 ppm, with an average of 58 ppm. Based on the average fluorine content plus two standard deviations, the uncontrolled fluorine emission rate is 0.018 lb/MMBtu. Expressed in terms of HF, the uncontrolled emission rate is 0.019 lb/MMBtu. (Using the same methodology, the uncontrolled emission rate for Colorado/Utah bituminous coal would be slightly higher, 0.026 lb/MMBtu as HF.)

EPA's February 1998 study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units Final Report to Congress (Utility RTC) only reports

HF removal for two control technologies: wet scrubbers and dry scrubbers. Of those two technologies, the backup document for Section 13.3.3 of the report indicates 44% HF removal for a wet scrubber and 95% HF removal for a dry scrubber/fabric filter.[150]

During a DOE-NETL sponsored test of four types of sorbent injection, no HF removal was identified.[151] Although several vendor brochures for different types of sorbent made claims of over 90% removal, no corresponding published literature results could be found.

<u>Energy Impacts</u>

This subsection lists the energy impacts of the feasible HF control options. The primary energy impact for either option is a parasitic load on the system. A parasitic load refers to energy produced by the generator and used for an ancillary device. In order to send a desired amount of power to the transmission grid, a power plant must produce power in excess of the desired amount to compensate for the parasitic load. The end result of a higher parasitic load is higher emissions to produce the same amount of power for sale. The energy impacts for the HF control options are presented in Table 10.29.

Table 10.29 – Summary of Energy Impacts for Fluorides Control Options

Control Option	Parasitic Load (%) (1)	Parasitic Load (MW) (2)	Notes
Dry Scrubber	0.7%	11.1	--
Wet Scrubber	2%	34.5	Higher parasitic load due to additional electric motor driven equipment such as recirculating pumps, waste dewatering pumps, reagent preparation equipment, and larger fans
Duct Sorbent Injection (DSI) (3)	--	--	--
Furnace Sorbent Injection (FSI) (3)	--	--	--

Notes:
(1) Based on *Alstom Power WFGD Presentation*, September 3, 2001.
(2) For the 1,590-MW WPEA Facility.
(3) Energy impacts not estimated for these control technologies due to absence of established control efficiency values.

150 EPA Document No. OAR-2002-0056-5736.
151 http://www.netl.doe.gov/coal/E&WR/pm/pubs/40718final.PDF

Environmental Impacts

This subsection lists the environmental impacts of the feasible HF control options. A summary of the environmental impacts is included in Table 10.30 below. For a complete discussion of the environmental impacts of the technologies, refer to the detailed environmental impacts assessment in Section 10.5.3 of this BACT analysis.

Table 10.30 – Summary of Environmental Impacts for Fluorides Control Option [(1)]

Environmental Impact	Dry Scrubber	Wet Scrubber
Water Consumption	552 MMgal/yr for 3 units	773 MMgal/yr for 3 units
Air Emissions	• 66 tpy HF for three units (see Table 10.11 for other pollutants). • Minimal fugitive emissions since lime reagent would be stored in silos. • Not expected to emit a visible plume.	• 754 tpy HF for three units (see Table 10.11 for other pollutants). • Fugitive emissions would result from storing limestone reagent in piles. • Would emit a visible steam plume.
Wastewater	No wastewater stream produced.	Would produce a wastewater stream containing dissolved suspended chemicals potentially requiring specialized handling and treatment.
Solid Waste	192,199 tpy per unit	217,538 tpy per unit

Notes:
(1) Environmental impacts not estimated for sorbent injection technologies due to absence of established control efficiency values for these technologies.

Economic Impacts

Since WPEA is not proposing to eliminate any control technology based on cost, the economic impacts for fluorides ($/ton) are not presented here.[152]

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the feasible control technologies are evaluated below, starting with the most effective control. A dry scrubber is the top control option since it achieves the highest control efficiency.

Dry Scrubber

A case-by-case consideration of energy, environmental, and economic impacts for dry scrubbing is presented below.

[152] However, Table 10.13 provides the annualized costs for the more effective fluorides control technologies (i.e., dry scrubbing and wet scrubbing).

Energy Impacts

As shown in Step 3, dry scrubbing presents a nominal energy penalty, which is consistent with other control technology types and does not preclude the selection of this technology as BACT.

Environmental Impacts

As shown in Step 3, dry scrubbing results in the lowest HF and overall air emissions of the feasible technologies. Dry scrubbing will result in a consumptive water use; however, this use is a low percentage of the overall water needs of the facility. Dry scrubbing will create a solid waste stream; however, the waste will be only approximately 25% of the overall Facility waste stream. Lime fed to dry scrubber systems will have minimal material handling emissions since the lime will be stored in silos. These environmental impacts do not preclude the selection of this technology as BACT.

Economic Impacts

The economic impacts of dry scrubbing were not evaluated for HF as they do not preclude the selection of this technology as BACT.

Since no energy, environmental, or economic impacts preclude its selection, WPEA selects dry scrubbing as BACT for fluorides from the PC-fired boilers.

Step 5 – Select BACT

Based on the preceding analysis, BACT for fluorides is the application of a dry scrubber and fabric filter combination with an emission limit of 9.7×10^{-4} lb/MMBtu of fluorides as HF on a 3-hour average basis.

As discussed in Section 8.1.10, the dry scrubber system may be inoperative for brief periods during startup due to insufficient flue gas flow rates and/or operating temperatures. During startup and shutdown periods, the boilers will utilize ultra low sulfur distillate fuel with negligible fluorine content and/or low sulfur coal. WPEA is not aware of any available technologies that can reduce HF emissions during startup and shutdown periods when the scrubber is inoperative. However, WPEA will minimize the number of startups that occur each year. Startups are expected to occur approximately 16 times per year per boiler. During startup and shutdown periods when the dry scrubber is not operational, the proposed fluorides BACT limit is 0.019 lb/MMBtu as HF.

10.5.8 Sulfuric Acid (H_2SO_4)

SO_2 is the product of the combustion of sulfur contained in the fuel. SO_3 can be generated as a result of the oxidation of SO_2 in the high-temperature environment of the furnace. This oxidation reaction can also occur across the catalyst bed installed for NO_X reduction. The amount of H_2SO_4 formed depends on the amount of SO_3 and water vapor present and the temperature of the flue gas.

The formation of H_2SO_4 occurs via two primary mechanisms. The first mechanism is the formation of liquid droplets of H_2SO_4 from the reaction of water vapor and SO_3. The second mechanism is through vapor condensation. As the bulk gas is cooled, H_2SO_4 condenses, and SO_3 vapor and H_2O vapor react to form additional H_2SO_4. The size of the H_2SO_4 particle formed depends on the cooling rate. Rapid mixing of a dry gas stream with a wet atmosphere can create very fine H_2SO_4 particles. H_2SO_4 particles formed under the first mechanism have diameters on the order of 0.5 μm, while rapidly mixed gas streams form H_2SO_4 particles with diameters on the order of 0.028 to 0.064 um.[153]

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

The lower emitting processes/practices described in the SO_2 BACT analysis indirectly control H_2SO_4 emissions by limiting the amount of sulfur available to form H_2SO_4. These lower emitting processes/practices include the following:

Coal Selection

Coal-fired boiler H_2SO_4 emissions are directly proportional to the amount of sulfur contained in the coal. Therefore, the potential for H_2SO_4 formation can be reduced by firing coal with a low sulfur content. Coal reserves in Wyoming's Powder River Basin are considered low sulfur coal reserves.[154] Additionally, Colorado and Utah bituminous coals are also considered low sulfur coals.

Coal Cleaning

Coal normally contains quantities of inorganic elements such as iron, aluminum, silica, and sulfur. These elements occur primarily in ash-forming mineral deposits embedded within the coal but are also present to a lesser degree within the organic coal structure. Minimizing the inorganic content of the coal can reduce the amount of sulfur available to form H_2SO_4 in the exhaust. Coal cleaning is a process that removes the mineral ash matter from the coal after it is extracted from the ground.

The amount of ash, the manner in which it is included in the coal assemblage, and the degree to which it can be removed vary widely with different coals. The application

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[153] Buckley, W. and B. Altshuler, "Sulfuric Acid Mist Generation in Utility Boiler Flue Gas," www.energypulse.net, 2003.

[154] U.S. EPA, Office of Air and Radiation, Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model, EPA Document No. EPA 430/R-02-004, Table 8.1, March 2002.

and extent of coal cleaning depends on the particular mine and mining technique. Eastern coals are typically cleaned because Eastern deep mines produce a raw coal product typically containing 25% to 60% ash that cannot be sold without cleaning.[155] Conversely, surface mines tend to employ coal cleaning less often due to the effectiveness of overburden removal and the thickness of the coal seam.

Coal Refining

Subbituminous coal may contain significant amounts of bound moisture and other inorganic elements such as sulfur and nitrogen. Minimizing the sulfur content of the coal reduces the potential formation of H_2SO_4 in the exhaust. Coal refining is a new process that employs both mechanical and thermal means to increase the quality of the coal by removing moisture, sulfur, nitrogen, and heavy metals. The thermal processing involves high pressure and temperature conditions to fracture mineral inclusions in the coal, removing included rock, pyritic sulfur, and moisture. As a result of the thermal process, the physical properties of the coal are modified to increase the heat rate, lower the moisture, and lower the ash content.[156]

Add-On Controls

Many of the add-on controls described in the SO_2 BACT analysis also tend to control H_2SO_4 emissions. Additionally, one add-on control from the particulate BACT analysis controls H_2SO_4 emissions. These add-on controls include the following:

Wet Scrubber

The wet scrubber is a once-through wet technology. In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The H_2SO_4 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport/disposal.

The wet scrubber can be further classified on the basis of the reagents used and the by-products generated. The typical reagents are lime and limestone. Additives, such as magnesium, may be added to the lime or limestone to increase the reactivity of the reagent. Seawater has also been used as a reagent since it has a high concentration of dissolved limestone. The reaction by-products are calcium sulfite and/or calcium sulfate. The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced depending on the desired by-product. The most common wet scrubber application utilizes limestone as the reagent and forced oxidation of the reaction by-products to form calcium sulfate.

Regenerable Wet Scrubber

The regenerable wet scrubber is a regenerable wet technology that uses sodium sulfite, magnesium oxide, sodium carbonate, amine, or ammonia as the sorbent for removal of H_2SO_4 from the flue gas. The spent sorbent is regenerated as needed to

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[155] Coal information from Energy Ventures Analysis, Inc., July 13, 2006.
[156] Factsheet, *What is K-Fuel™,* http://www.kfx.com/fact_sheets/WhatIsK-Fuel.PDF.

maintain effectiveness. Regenerable wet scrubbers achieve an H_2SO_4 emissions reduction equivalent to that of a non-regenerable wet scrubber.

Spray Dryer Absorber (Dry Scrubber)

The dry scrubber is a once-through dry technology. In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The H_2SO_4 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a dry form upon leaving the system and are subsequently captured in a downstream particulate collection device, typically a baghouse.

Circulating Dry Scrubber (CDS)

The CDS is a once-through dry technology. In a CDS, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and H_2SO_4. The by-products leave the absorber in a dry form with the flue gas and are subsequently captured in a downstream particulate collection device.

Limestone Injection Dry Scrubbing (LIDS)

The LIDS technology combines furnace sorbent injection (FSI) and dry scrubber technologies. In the LIDS system, limestone is injected into the furnace and a spray dryer absorber is installed between the air heater and particulate collection device. The reagent used in the spray dryer is a hydrated reaction by-product recycled from the particulate collection device.

Activated Carbon Bed

The only potentially applicable regenerable dry technology is based on the use of activated carbon. In this FGD process, the activated carbon is present in a moving bed through which the flue gas flows. The activated carbon serves as the sorbent for removal of the H_2SO_4. When the activated carbon becomes saturated, it is regenerated or disposed of in a solid waste disposal facility.

Electro-Catalytic Oxidation (ECO)

ECO is a multi-pollutant control technology under development by Powerspan Corporation. According to the company's website,[157] ECO is a multi-pollutant control technology that simultaneously controls SO_2, NO_X, Hg, and $PM_{2.5}$ (including acid aerosols). The ECO process is located downstream of a plant's primary particulate removal device (electrostatic precipitator or fabric filter). The process includes a reactor that oxidizes the gaseous pollutants; a scrubber that removes NO_X, SO_2, and the oxidizer reactor products; and a wet electrostatic precipitator that captures the oxidized pollutants.

In 2005, the ECO technology completed a 180-day pilot testing run at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio. The pilot unit processed a flue gas slipstream

[157] http://www.powerspan.com/technology/scrubber_overview.shtml.

that represented approximately one-third of the exhaust flow from a 156-MW front wall-fired boiler combusting coal.[158]

Furnace Sorbent Injection (FSI)

FSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb H_2SO_4. In the FSI technology, the reagent is injected directly into the furnace and the reaction product is collected in the downstream particulate collection device.

Furnace Sorbent Injection (FSI) + Wet Scrubber

FSI could presumably be used in conjunction with a wet scrubber.

Duct Sorbent Injection (DSI)

DSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb H_2SO_4. In the DSI technology, the reagent is injected into the ductwork between the air heater and particulate collection device.

Duct Sorbent Injection (DSI) + Wet Scrubber

DSI could presumably be used in conjunction with a wet scrubber.

Duct Sorbent Injection (DSI) + Dry Scrubber

DSI could presumably be used in conjunction with a dry scrubber.

Wet Electrostatic Precipitator (WESP)

A wet electrostatic precipitator (WESP) removes particulate (including H_2SO_4) in a three-step process: charging, collection, and removal. A WESP consists of a box containing rows of plates forming passages through which the flue gas flows. Centrally located in each passage are emitting electrodes energized with a high-voltage, negative polarity direct current. The voltage applied is high enough to ionize the gas molecules close to the electrodes, resulting in a corona current of gas ions from the emitting electrodes across the gas passages to the grounded collecting plates. When passing through the flue gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The electric field forces the charged particles out of the gas stream towards the grounded plates, and there they collect in a layer. Removal of particles from the collecting electrodes is accomplished by continuously washing the collection surface using liquid. WESPs are more commonly used in applications where the gas stream has a high moisture content, is below the dew point, or includes sticky particulate.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable H_2SO_4 control technologies identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies

[158] http://www.powerspan.com/technology/scrubber_demonstration.shtml.

that have been installed and operated successfully on PC-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[159] A technology that has not been demonstrated on PC-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Coal Selection

Coal selection is a reliable method for minimizing the amount of sulfur available for H_2SO_4 formation. Low sulfur coals (e.g., PRB coal and Colorado/Utah bituminous coal) are available for use at the Facility. For this reason, the use of low sulfur coals is considered technically feasible.

Coal Cleaning

Coal cleaning is a demonstrated technology for reducing the amount of sulfur present in the coal in some situations. Coal cleaning provides a benefit for coal containing significant overburden or for high-sulfur eastern bituminous coals containing appreciable amounts of pyritic sulfur. However, PRB coal is surface mined from thick coal seams with very little overburden. The PRB coal mining techniques produce a coal product with very little rock and non-combustible material, other than what is bound in the coal. PRB coal contains low sulfur levels, typically below 1%, and low ash levels, typically below 6%. For these reasons, coal cleaning is not typically performed on PRB coal, and WPEA is not aware of any large-scale PRB coal cleaning operations in existence. Additionally, Utah and Colorado coals are not normally cleaned due to the low characteristic ash contents of these coals (typically 8%-11%).[160]

Due to the lack of coal cleaning facilities, there is currently no reliable source of cleaned western coal to supply the WPEA Facility. Since a sufficient supply of cleaned western coal is not available, coal cleaning is determined to be technically infeasible.

Coal Refining

Coal refining is not a demonstrated technology for controlling H_2SO_4 emissions from large-scale PRB coal combustion. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

A company known as KFx is the only vendor known to offer refined PRB coal. This refined product is marketed under the name "K-Fuel™" and was first reported as being produced in commercial quantities in December 2005.[161] The first two production runs were reported to have produced 200 tons (i.e., enough fuel to supply the WPEA boilers for approximately 13 minutes). According to the company's website (http://kfx.com), the facility will only be able to produce 750,000 tons

[159] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.
[160] Coal information from Energy Ventures Analysis, Inc., July 13, 2006.
[161] http://kfx.com/documents/750KPlant123005.pdf.

annually, once operational, a level below the annual coal throughput for the proposed WPEA Facility.

Based on the lack of refined PRB coal production capacity, coal refining is not considered an available technology for H_2SO_4 emissions reduction. Therefore, per EPA's Draft NSR Workshop Manual, coal refining is determined to be technically infeasible.

WPEA is not aware of refining being applied to Colorado or Utah bituminous coal due to the lower moisture contents and higher heating values already shown by those fuels. Thus, coal refining is technically infeasible for Colorado and Utah bituminous coals.

Wet Scrubber

Wet scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers. Wet scrubbers that use limestone, lime, magnesium-enhanced lime, forced oxidation, and inhibited oxidation are all considered technically feasible control technologies. Wet scrubbers using seawater are determined to be technically infeasible because the Facility is located over 100 miles from the closest source of seawater.

Regenerable Wet Scrubber

Feasibility evaluations for the various regenerable wet scrubber configurations are presented below.

A) The sodium sulfite and ammonia-based technologies have been commercially demonstrated and are available from a number of suppliers. These technologies are considered technically feasible. As stated in Step 1 above, regenerable wet scrubbers achieve an H_2SO_4 emissions reduction equivalent to that of a wet scrubber.

Regarding the evaluation of multiple control technologies that achieve an equivalent level of performance, EPA's Draft NSR Manual allows applicants to review only the lowest-cost option if several potential options achieve an essentially identical level of performance.[162] As stated above, a regenerable wet scrubber would be expected to achieve essentially identical environmental performance as a wet scrubber. Additionally, utilizing a regenerable wet scrubber would represent a higher cost than a wet scrubber (e.g., capital cost for regeneration process equipment). Therefore, in accordance with EPA guidance, WPEA will evaluate only the less costly option that achieves equivalent performance (i.e., WPEA will only carry wet scrubber technology forward in the analysis, as opposed to regenerable wet scrubber).

[162] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.20.

This BACT methodology was allowed by the NDEQ with no adverse comments from EPA during permitting of the Whelan Energy Center in March 2004.[163]

B) Only one application of the magnesium oxide scrubber technology was found. This application was at the Exelon Eddystone Station in Pennsylvania and was made possible because of a long-term commercial arrangement with a neighboring chemical company that regenerated the sorbent and sold the sulfur product. This has been the only application of this technology. Due to the lack of self-contained commercial applications of the magnesium oxide technology, WPEA expects that significant time delays and resource penalties would be required in order to develop this technology for the WPEA Facility. Per EPA's Draft NSR Manual, this is not the Agency's intent, and technologies that would present these problems are not considered available:

> *"A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique.*[164]

Accordingly, magnesium oxide technology is not considered available. Thus, magnesium oxide technology is determined to be technically infeasible.

C) No record of the commercial application of sodium carbonate and amine based regenerable technologies was found. Due to the lack of commercial application of these technologies, WPEA expects that significant time delays and resource penalties would be required in order to develop these technologies for the WPEA Facility. Per EPA's Draft NSR Manual, this is not the Agency's intent.[165] Accordingly, these technologies are not considered available. Thus, sodium carbonate and amine-based technologies are determined to be technically infeasible.

Dry Scrubber

Dry scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers. For these reasons, dry scrubbers are considered a technically feasible control technology.

Circulating Dry Scrubber (CDS)

CDS have only been domestically applied to two smaller coal-fired boilers: the 80-MW Neil Simpson Unit 2 and the 50-MW[166] LG&E Roanoke Valley Unit 2, both of which have experienced problems with lime utilization and corrosion.[167] CDS have

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[163] NDEQ Construction Permit Fact Sheet, Whelan Energy Center, March 2004.
[164] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.
[165] Ibid.
[166] Capacity from Powergen: http://www.pwrgen.com/DB_Hist/Projects_2.asp.
[167] Supplemental BACT information provided by WYGEN to the Wyoming Department of Environmental Quality, July 1, 2002.

not been demonstrated at the 530-MW scale of the WPEA Facility. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible. Regarding availability, EPA's Draft NSR Manual states the following:

> *"Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available..."*[168]

The size and scale differences between a 50-MW or 80-MW unit and a 530-MW unit would require significant design, testing, and modeling to evaluate the feasibility of scaling up CDS to the size of WPEA's proposed project. Scale-up efforts for fluidized bed systems are known to be particularly problematic and would be expected to require a significant level of effort and cost. Since the only demonstrated applications of the CDS technology have been on boilers approximately one-seventh the size of the WPEA boilers, CDS are not considered to have been applied to full-scale operations. Therefore, CDS are not considered available. Consequently, CDS are considered technically infeasible in accordance with EPA's Draft NSR Manual.

<u>Limestone Injection Dry Scrubbing (LIDS)</u>

LIDS is not a demonstrated technology for controlling H_2SO_4 emissions from large-scale coal combustion. The LIDS technology is still undergoing significant research and development aimed at improving performance and increasing the scale of application.[169] Per EPA's Draft NSR Manual, technologies that have not yet been applied to full-scale operations are not considered available.[170] Since LIDS is still under development and is not commercially available for large-scale operations, this technology is not considered available. Consequently, the LIDS technology is determined to be technically infeasible.

<u>Activated Carbon Bed</u>

Based on a review of the RBLC database, EPA's National Coal Database Spreadsheet, and available industry literature, activated carbon bed technology is not a demonstrated H_2SO_4 removal technology for PC-fired boilers. WPEA has not located any commercial sales of activated carbon bed technology for H_2SO_4 removal. EPA's Draft NSR Manual states the following:

> *"A control technique is considered available… if it has reached the licensing and commercial sales stage of development."*[171]

Since activated carbon bed technology for H_2SO_4 removal has not reached the commercial sales stage of development, this technology is not considered available. Furthermore, activated carbon bed technology for H_2SO_4 removal has not been deployed on an existing source with similar gas stream characteristics (i.e., flow rate,

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[168] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.11.
[169] Nolan, Paul S., The Babcock & Wilcox Company, *Flue Gas Desulfurization Technologies for Coal-Fired Power Plants,* Presented at the Coal-Tech 2000 International Conference. The company has not published subsequent information regarding the development of this technology.
[170] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.11.
[171] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.

temperature, particulate loading, etc.). Therefore, activated carbon bed technology is not considered available. Consequently, activated carbon bed technology is determined to be technically infeasible for H_2SO_4 removal.

Electro-Catalytic Oxidation (ECO)

The ECO technology is still in the pilot plant stage of development. To date, the only application of this technology has been a pilot facility processing a flue gas slip stream from a coal-fired boiler.[172] This technology has not been demonstrated for full-scale operations. EPA's Draft NSR Manual states the following regarding technologies in the pilot stage of development:

> *"…technologies in the pilot scale testing stages of development would not be considered available for BACT review."*[173]

Since the ECO technology has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available. Therefore, the ECO technology is determined to be technically infeasible.

Furnace Sorbent Injection (FSI)

Although there is little operating experience supporting the effectiveness of FSI in removing H_2SO_4 from PC-fired boiler exhaust, FSI is considered technically feasible.

Furnace Sorbent Injection (FSI) + Wet Scrubber

Although there is limited operating experience supporting the long-term effectiveness of an FSI + wet scrubber system in removing H_2SO_4 from PC-fired boiler exhaust, the combination of FSI + wet scrubber is considered technically feasible.

Duct Sorbent Injection (DSI)

Although there is limited operating experience supporting the long-term effectiveness of DSI in removing H_2SO_4 from PC-fired boiler exhaust, DSI is considered technically feasible.

Duct Sorbent Injection (DSI) + Wet Scrubber

Although there is little operating experience supporting the long-term effectiveness of a DSI + wet scrubber system in removing H_2SO_4 from PC-fired boiler exhaust, the combination of DSI + wet scrubber is considered technically feasible.

Duct Sorbent Injection (DSI) + Dry Scrubber

In order for a DSI system to function effectively, humidification to a close approach to the adiabatic saturation temperature of the flue gas is required.[174] Therefore,

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[172] http://www.powerspan.com/technology/scrubber_demonstration.shtml.
[173] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.18.
[174] Nolan, Paul S., The Babcock & Wilcox Company, *Flue Gas Desulfurization Technologies for Coal-Fired Power Plants,* Presented at the Coal-Tech 2000 International Conference.

installing a DSI system in conjunction with a dry scrubber would interfere with the ability of the spray dry scrubber to evaporate the moisture in the reagent slurry and function properly. Since the DSI system would interfere with operation of the dry scrubber, the DSI + dry scrubber combination is determined to be infeasible.

Wet Electrostatic Precipitator (WESP)

WESP systems have been shown to remove H_2SO_4 mist from exhaust streams and are considered technically feasible.

In summary, the technically feasible control technologies identified for the control of H_2SO_4 emissions are:

- Coal Selection
- Wet Scrubber
- Regenerable Wet Scrubber
- Dry Scrubber
- Furnace Sorbent Injection (FSI)
- FSI + Wet Scrubber
- Duct Sorbent Injection (DSI)
- DSI + Wet Scrubber
- Wet Electrostatic Precipitator (WESP)

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. Table 10.31 ranks the feasible H_2SO_4 control technologies by effectiveness when applied to the Facility. Sine a new PC-fired boiler would be expected to include some form of SO_2 control, typically a wet or dry scrubber, sorbent injection and the WESP control technologies are evaluated in combination with a wet scrubber. Additionally, due to the similarity in control, duct sorbent injection and furnace sorbent injection are evaluated as one technology. Due to their identical control efficiencies, wet scrubber and regenerable wet scrubber technologies are addressed as a single technology for the remainder of the analysis.

Table 10.31 – Ranking of H_2SO_4 Control Technologies by Effectiveness

Control Technology	Control Efficiency	Emission Rate (lb/MMBtu)
Dry Scrubber + WESP	98% (1)	6.0×10^{-4}
Wet Scrubber + WESP	97.5% (1)	8.2×10^{-4}
Dry Scrubber	92% (1)	2.4×10^{-3}
Sorbent Injection + Wet Scrubber	63% to 91% (1)	6.6×10^{-3}
Wet Scrubber	50% (2)	0.016
Low Sulfur Coal	Baseline (3)	0.03

Notes:

(1) Based on engineering estimates and vendor information. Consistent with baseline information explained in footnote (3) below.

(2) From *Furnace Injection of Alkaline Sorbents for Sulfuric Acid Removal, Final Report,* DOE-NETL.

(3) Since the boiler design will be based on PRB coal, baseline emissions assume the use of PRB coal and are derived from burning 0.32% sulfur by weight PRB coal with an assumed SO_2 to SO_3 oxidation rate of 2.5%. Control efficiencies listed for other control technologies are incremental reductions over the baseline.

Technical publications, vendor information, permits and permit applications, and the RBLC database were reviewed to determine the range of reported control efficiencies for each of the technically feasible H_2SO_4 reduction technologies identified in Step 2. Because regulation of H_2SO_4 emissions is a relatively recent development, there are few instances where the performance of these control technologies for H_2SO_4 emission control have been evaluated.

As discussed in the SO_2 BACT analysis, low sulfur western coal is intended for use in the Facility boilers. The H_2SO_4 reduction achieved by implementing this lower emitting process/practice is considered the baseline.

Energy Impacts

This subsection lists the energy impacts of the feasible H_2SO_4 control options. Energy impacts include parasitic load (i.e., energy produced by the generator and used for an ancillary device) and pressure drop across the control device. The energy impacts for the H_2SO_4 control options are presented in Table 10.32.

Table 10.32 – Summary of Facilitywide Energy Impacts for H_2SO_4 Control Options

Control Option	Total Energy Impact for 1,590-MW Facility
Dry Scrubber + WESP	• 11.1 MW parasitic load for dry scrubber • 3.62 MW power required for WESP (1) • Additional electricity required for pumps to circulate the wash water used to rinse the collected material from the WESP collection surfaces
Wet Scrubber + WESP	• 34.5 MW parasitic load for wet scrubber • 3.62 MW power required for WESP (1) • Additional electricity required for pumps to circulate the wash water used to rinse the collected material from the WESP collection surfaces
Dry Scrubber	11.1 MW parasitic load
Sorbent Injection + Wet Scrubber	• 34.5 MW parasitic load for wet scrubber • 0.001 atm ΔP for Sorbent Injection (2) • Possible heat transfer efficiency losses due to fouling from sorbent material (2) • Electricity required to process and handle sorbent powder or slurry
Wet Scrubber	34.5 MW parasitic load

Notes:

(1) Based on a corona power of 800 Watts per 1,000 acfm per the EPA Air Pollution Training *Institute's ESP Design Parameters and Their Effects on Collection Efficiency*.

(2) From *Furnace Injection of Alkaline Sorbents for Sulfuric Acid Removal, Final Report,* DOE-NETL.

Environmental Impacts

The environmental impacts list is organized by environmental impact type. The impacts are provided and discussed below.

Water Consumption. White Pine County, Nevada, is considered an arid region receiving an annual rainfall of approximately 9 inches.[175] Thus, water consumption is an important consideration. Estimated water consumption requirements for the Facility are summarized in Table 10.33 below.

[175] http://budget.state.nv.us/BR02/BR02Enviroreport.doc

Table 10.33 – Summary of Estimated Water Consumption of a WESP for 1,590 MW Facility

Scrubber Type	Water Consumption (MMgal/year)	Incremental Consumption (MMgal/year)	Incremental Consumption (%)
Wet Scrubber + WESP	832	59	8%
Wet Scrubber	773	162	27%
Dry Scrubber + WESP	611	59	11%
Dry Scrubber	552	--	--

Note: Based on engineering estimates and vendor information.

Air Impacts – Fugitive Emissions. Fugitive emissions from the facility will be dictated partially by the scrubber type ultimately selected.

Fugitive PM/PM_{10} emissions from a wet scrubbed system occur from the storage (typically stored in exposed piles) and handling (numerous handling points) of the limestone and the handling and disposal of the large amount of byproducts. Byproducts from a wet scrubber system will be approximately 53,300 tons per year greater than from a dry scrubber system.

Lime used in a dry scrubber system would be stored in enclosed silos with no fugitive emissions. Emissions from the silos would be controlled with vent filters.

Air Impacts – Visible Plume. A wet scrubber system would emit a visible steam plume. During warm, dry weather, the plume should dissipate within a few hundred yards of the stack discharge. During cooler weather or humid conditions, the steam plume will be visible for a greater distance from the stack. The plume may be considered unfavorable from an aesthetic perspective. A WESP might reduce the presence of a visible plume by removing condensed vapor from the exhaust. Properly operated dry scrubbers do not typically emit a visible plume.

Air Impacts – Concentrations. On an equal emission rate basis, the near-field ground level concentrations for all pollutants will generally be higher with a wet scrubber system compared to a dry scrubber system. The higher ground level concentrations result because a wet scrubber system produces a cooler, wetter, less buoyant plume. This effect might be enhanced by a WESP, where the exhaust would further contact water, potentially lowering the plume temperature further.

Water Impacts – Wastewater. Wet scrubbers and WESP systems create wastewater streams. Wastewater concerns are discussed in Table 10.34 below.

Table 10.34 – Wastewater Impacts for H_2SO_4 Control Options

Control Option	**Wastewater Impact**
Dry Scrubber + WESP	A dry scrubber does not create a wastewater or blowdown stream. The WESP collects H_2SO_4 by condensing the pollutants and collecting the condensate by electrical attraction. The low pH of the condensate makes it very corrosive, which in turn makes the cycled wash water very corrosive. In order to control the pH of the wash water, a portion of it must be constantly blown down and replaced with fresh water. The blowdown stream must also be chemically neutralized prior to discharge. The neutralized blowdown stream must then be discharged and treated in accordance with the applicable regulations.
Wet Scrubber + WESP	A wet scrubber would produce a wastewater stream containing concentrations of dissolved and suspended chemicals potentially requiring specialized water handling and treatment equipment. In addition, water treatment might be required for the wet scrubber plant's wastewater prior to disposal in the evaporation pond to remove heavy metals (which are 15% to 25% higher for a plant with wet scrubbing than a plant with dry scrubbing) and chlorides (which are 547% higher for a plant with wet scrubbing than with a plant with dry scrubbing). A WESP would create a blowdown stream that must be chemically neutralized prior to discharge. The neutralized blowdown stream must then be discharged and treated in accordance with the applicable regulations.
Dry Scrubber	A dry scrubber does not create a wastewater or blowdown stream.
Sorbent Injection + Wet Scrubber	Sorbent injection would not be expected to create a wastewater stream. A wet scrubber would produce a wastewater stream containing concentrations of dissolved and suspended chemicals potentially requiring specialized water handling and treatment equipment. In addition, water treatment might be required for the wet scrubber plant's wastewater prior to disposal in the evaporation pond to remove heavy metals (which are 15% to 25% higher for a plant with wet scrubbing than a plant with dry scrubbing) and chlorides (which are 547% higher for a plant with wet scrubbing than with a plant with dry scrubbing).
Wet Scrubber	A wet scrubber would produce a wastewater stream containing concentrations of dissolved and suspended chemicals potentially requiring specialized water handling and treatment equipment. In addition, water treatment might be required for the wet scrubber plant's wastewater prior to disposal in the evaporation pond to remove heavy metals (which are 15% to 25% higher for a plant with wet scrubbing than a plant with dry scrubbing) and chlorides (which are 547% higher for a plant with wet scrubbing than with a plant with dry scrubbing).

Solid Waste Impacts. Solid waste impacts depend primarily on the scrubber type and the use of sorbent injection. The use of a WESP would not be expected to significantly impact the amount of solid waste produced since a fabric filter baghouse could be used if a WESP were not selected. Scrubber solid waste production for each control option is summarized in Table 10.35.

Table 10.35 – Solid Waste Impacts for H_2SO_4 Control Options [(1)]

Scrubber Type	Scrubber Waste Produced per Unit (tons per year)	Incremental Waste Produced for 3 Units (tons per year)	Incremental Waste Disposal Space for 3 Units (acre-feet/year)
Wet Scrubber + WESP	217,538 [(2)]	76,017 [(2)]	801 [(2)]
Wet Scrubber	217,538	76,017	801
Dry Scrubber	192,199	--	--

Notes:
(1) Assumes 100% capacity factor. Based on engineering estimates and vendor information.
(2) Some additional amount of waste may be created from the treatment of wastewater from the WESP but that quantity has not been estimated.

Economic Impacts

Per EPA's Draft NSR Manual, average and incremental cost effectiveness are the two economic criteria that are considered in Step 3 of the BACT analysis.[176] A summary of the economic impacts analysis is provided in Table 10.36 below. Table 10.37 provides additional details of the analysis.

Table 10.36 – Summary of Economic Impacts Analysis for H_2SO_4 Control Options for a 530 MW Unit

Control Option	Emissions (lb/hr)	Emissions (tpy)	Total Annualized Cost over Baseline ($/year)	Cost Effectiveness over Baseline ($/ton)	Incremental Cost Effectiveness over Dry Scrubber ($/ton)
Dry Scrubber + WESP	3.1	13.4	$21,346,000	$32,492	$174,987
Wet Scrubber + WESP	4.2	18.4	$32,859,000	$49,988	$524,101
Dry Scrubber	12.1	53.2	$14,390,000	$23,314	--
Baseline	153	670	--	--	--

Notes: Baseline is 0.32% sulfur by weight PRB coal with 2.5% total oxidation.
Costs are determined for a 530 MW plant at 100% capacity.
Dry scrubber assumes 92% control.
Dry scrubber with sorbent injection assumes 96% control.
Wet scrubber with WESP assumes 97.5% control.
Dry scrubber with WESP assumes 98% control.

[176] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.31.

Table 10.37 – Summary of Economic Impacts Analysis for H_2SO_4 Control Options for a 530 MW Unit

	Dry Scrubber	Wet Scrubber + WESP	Dry Scrubber + WESP	Notes
Capacity, MW	532	523	530	
SO2 Content, lb/MMBtu	0.78	0.78	0.78	
Removal	92.0%	97.25%	98%	
Emission Rate, lb/MMBtu	0.0024	0.0008	0.0006	
Direct capital costs				(1)
Purchased Equipment	$45,764,000	$110,636,000	$76,009,000	
Direct Installation	$8,131,000	$18,518,000	$11,458,000	
Indirect capital costs	$15,748,000	$37,466,000	$25,360,000	(2)
Total Capital Cost	$69,643,000	$166,620,000	$112,827,000	
Total capital required, $/kW (net)	131	319	213	
Annual costs				
Lost energy sale revenue	$1,766,000	$5,712,000	$2,431,000	(3)
Lime	$1,579,000	--	$1,579,000	
Limestone	--	$1,285,000	--	
Waste	$197,000	$284,000	$197,000	
Labor	$765,000	$1,220,000	$837,000	(4)
Maintenance material	$539,000	$1,258,000	$841,000	(5)
Indirects	$1,393,000	$3,332,000	$2,257,000	(6)
Capital recovery	$8,150,000	$19,498,000	$13,203,000	
Total annual costs	$15,167,000	$33,310,000	$22,124,000	
Incremental costs	--	$18,142,000	$6,956,000	
H_2SO_4 emissions, tpy	53	18	13	
Incremental removal, tpy	--	35	40	
Incremental cost, $/ton	--	$524,101	$174,987	

Notes:

(1) Includes the scrubber, baghouse, and WESP.
(2) Includes AFUDC, contingency, engineering, construction and field expenses, startup, and performance tests.
(3) Lost energy revenue caused by higher auxiliary load consumed by the WESP.
(4) An additional 8 operations and maintenance personnel are assumed for a dry scrubber, an additional 12 are assumed for a wet scrubber, and an additional 0.75 is assumed for WESP.
(5) Maintenance material equal to 1% of direct capital costs.
(6) Includes administrative and insurance.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the control technologies are evaluated below, starting with the most effective control.

Dry Scrubber + WESP

A case-by-case consideration of energy, environmental, and economic impacts for dry scrubber + WESP is presented below.

Energy Impacts

As discussed in Step 3, the WESP system would require power to charge the plates and remove the particles. Additionally, WESP system pumps would use energy to circulate the wash water used to rinse the collected material from the WESP collection surfaces. Thus, the energy impacts from the dry scrubber + WESP combination represent a negative environmental impact and an undesirable compromise for the incremental additional control provided.

Environmental Impacts

As shown in Step 3, a WESP system has an incremental consumption of 59,000,000 gallons of water per year. Minimization of water consumption would allow for future residential, commercial, and industrial growth in this arid region. WPEA has demonstrated a commitment to minimal water use by selecting a semi-dry cooling tower system to significantly reduce the amount of water consumed by the Facility.

Considering that the Facility will be located in an arid region, the water consumption impacts for the WESP component of the dry scrubber + WESP combination represent a negative environmental impact.

Economic Impacts

As shown in Step 3, the average cost of controlling H_2SO_4 with the dry scrubber + WESP combination would be $32,492 per ton. This average cost is extremely high and represents a significant negative economic impact. Additionally, the incremental cost for applying the dry scrubber + WESP combination would be $174,987 per additional ton of H_2SO_4 removed. This extremely high incremental cost represents a significant negative economic impact.

Due to the negative energy, environmental, and economic impacts, the dry scrubber + WESP combination is not selected as BACT. The wet scrubber + WESP combination is evaluated as the next most effective technology in the top-down process.

Wet Scrubber + WESP

A case-by-case consideration of energy, environmental, and economic impacts for wet scrubber + WESP is presented below.

Energy Impacts

As documented in Step 3, a wet scrubber would demand a parasitic load of up to 34.5 MW for the Facility. This would be enough energy to provide for approximately 29,000 homes.[177] Thus, the energy requirements for wet scrubbing represent a negative energy impact. Installing a control technology that would consume an energy equivalent of 29,000 homes would not represent a judicious use of energy by the WPEA Facility.

Additionally, the WESP system would require significant power to charge the plates and remove the particles. Additionally, WESP system pumps would use energy to circulate the wash water used to rinse the collected material from the WESP collection surfaces. Thus, the energy impacts from the wet scrubber + WESP combination represent a negative environmental impact and an undesirable compromise for the incremental additional control provided.

Environmental Impacts

As shown in Step 3, a wet scrubber system has an incremental consumption of 221,000,000 gallons of water per year. That additional water would be capable of supporting approximately 841 additional homes.[178] Beyond the water use for a wet scrubber, a WESP system has an incremental consumption of 59,000,000 gallons of water per year. Minimization of water consumption will allow for future residential, commercial, and industrial growth in this arid region. WPEA has demonstrated a commitment to minimal water use by selecting a semi-dry cooling tower system to significantly reduce the amount of water consumed by the Facility.

Considering that the Facility will be located in an arid region, the water consumption impacts for wet scrubbing represent a negative environmental impact.

As discussed in Step 3, fugitive PM/PM_{10} emissions from a wet scrubbed system would result from the storage and handling of the limestone and the handling and disposal of the large amount of byproducts. These low-release height fugitive emissions typically manifest their highest ambient concentrations just beyond the facility boundaries. While fugitive dust would not cause an exceedance of the NAAQS, activities that result in fugitive dust emissions should be avoided to the extent practicable.

A wet scrubber and WESP would both create wastewater streams that would have to be handled and treated in accordance with the applicable regulations. Creating new wastewater streams would be an undesirable compromise for the incremental additional control provided.

Finally, a wet scrubber system would generate 76,018 tons per year of incremental solid waste production at the Facility. Significantly increasing solid waste production would not be a desirable compromise for the marginally better H_2SO_4 air

[177] http://www.utilipoint.com/issuealert/print.asp?id=1728
[178] Based on 1996 AWWA survey for Nevada homeowners.

emissions performance that might be achieved with a wet scrubber + WESP combination.

Economic Impacts

As shown in Step 3, the average cost of controlling H_2SO_4 with the wet scrubber + WESP combination would be $49,988 per ton. This average cost is extremely high and represents a significant negative economic impact. Additionally, the incremental cost for applying the wet scrubber + WESP combination would be $524,101 per additional ton of H_2SO_4 removed. This extremely high incremental cost represents a significant negative economic impact.

Due to the negative energy, environmental, and economic impacts, the wet scrubber + WESP combination is not selected as BACT. The dry scrubber technology is evaluated as the next most effective technology in the top-down process.

Dry Scrubber

A case-by-case consideration of energy, environmental, and economic impacts for dry scrubbing is presented below.

Energy Impacts

As shown in Step 3, dry scrubbing presents a nominal energy penalty, which is consistent with other control technology types and does not preclude the selection of this technology as BACT.

Environmental Impacts

As shown in Step 3, dry scrubbing will result in a consumptive water use; however, this use is a low percentage of the overall water needs of the facility. Dry scrubbing will create a solid waste stream; however, the waste will be only approximately 25% of the overall Facility waste stream. Lime fed to dry scrubber systems will have minimal material handling emissions since the lime will be stored in silos. These environmental impacts do not preclude the selection of this technology as BACT.

Economic Impacts

As shown in Step 3, the cost of H_2SO_4 control with dry scrubbing is $23,314 per ton. Although this high cost represents a significant negative economic impact that would normally preclude the use of a dry scrubber as BACT, WPEA has committed to utilizing a dry scrubber for SO_2 control. Thus, economic impacts do not preclude the use of a dry scrubber as BACT.

Since no energy, environmental, or economic impacts preclude its selection, WPEA selects dry scrubbing as BACT for H_2SO_4 emissions from the PC-fired boilers.

Step 5 – Select BACT

Based on the preceding analysis, dry scrubbing is selected as BACT for H_2SO_4 emissions. The proposed BACT emission limit is 0.0034 lb/MMBtu on a 3-hour average basis.

Note that a facility's NO_X control strategy is an important factor in establishing the H_2SO_4 emissions. The SCR catalyst material may likely contain vanadium pentoxide which acts as a catalyst in the oxidation reaction that produces SO_3 from SO_2. It should be noted that several other facilities permitted with relatively low H_2SO_4 emissions are not equipped with SCR (Nevada Power, White Pine Power and South Carolina Electric & Gas). Other sources such as Newmont did not take the SCR oxidation rate into consideration when estimating H_2SO_4 emissions, instead relying on the AP-42 general oxidation rate of 0.7% (WPEA's proposed emission rate conservatively assumes 2.5% oxidation of SO_2 to SO_3.).

As discussed in Section 8.1.10, the dry scrubber system may be inoperative for brief periods during startup due to insufficient flue gas flow rates and/or operating temperatures. During startup and shutdown periods, the boilers will utilize ultra low sulfur distillate fuel and/or low-sulfur coal to minimize H_2SO_4 emissions. During startup and shutdown periods when the dry scrubber is not operational, the proposed H_2SO_4 BACT limit is 0.05 lb/MMBtu. Additionally, WPEA will minimize the number of startups that occur each year. Startups are expected to occur approximately 16 times per year per boiler.

10.6 Auxiliary Boiler

This section contains the BACT analysis for the auxiliary boiler for each applicable regulated pollutant identified in Table 10.2.

10.6.1 Carbon Monoxide (CO)

Combustion is a thermal oxidation process in which carbon and hydrogen contained in a fuel combine with oxygen in the combustion zone to form CO_2 and H_2O. CO is generated during the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel. Properly designed and operated boilers typically emit low levels of CO. High levels of CO emissions could result from poor burner design or sub-optimal firing conditions.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for CO emissions control are combustion control techniques that maximize the thermal oxidation of carbon to minimize the formation of CO. Lower emitting processes/practices include the following:

Combustion Controls

Optimization of the design, operation, and maintenance of the combustion system is the primary mechanism available for lowering CO emissions. This process is often referred to as combustion controls. The combustion system design on modern oil-fired boilers provides all of the factors required to facilitate complete combustion. These factors include continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber. As a result, a properly designed furnace/combustion system is effective at limiting CO formation by maintaining the optimum furnace temperature and amount of excess oxygen.

Unfortunately, the addition of excess air and maintenance of high combustion temperatures for control of CO emissions may lead to increased NO_X emissions. Consequently, typical practice is to design the combustion system (specifically, the air/fuel mixture and temperature) such that CO emissions are reduced as much as possible without causing NO_X levels to significantly increase.

Proper operation and maintenance of the combustion system helps to minimize the formation and emission of CO by ensuring that the combustion system operates as designed. This includes maintaining the air/fuel ratio at the specified design point, having the proper air and fuel conditions at the burner, and maintaining the combustion air control system in proper working condition.

Add-On Controls

Potential add-on controls for the auxiliary boiler include the following:

Flares

Flares are commonly used in the control of organic-laden slipstreams from refineries and other chemical manufacturing processes with sufficient heating value. A flare operates by continuously maintaining a pilot flame that is typically maintained by natural gas. When a combustible exhaust stream is vented to a flare, the exhaust stream is ignited by the pilot flame at the flare tip, and combustion occurs in the ambient air above the flare.

Afterburning

Afterburners convert CO into CO_2 by utilizing simple gas burners to bring the temperature of the exhaust stream up to 1,400 °F to promote complete combustion. Operation of afterburners would require significant amounts of natural gas.

Catalytic Oxidation

A catalytic oxidizer converts the CO in the combustion gases to CO_2 at temperatures ranging from 500 °F to 700 °F in the presence of a catalyst. Catalytic oxidizers are susceptible to fine particles suspended in exhaust gases that can foul and poison the catalyst. Catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device; however, this would require reheating the exhaust gases to the required operating temperature for the catalytic process.

External Thermal Oxidation (ETO)

ETO promotes thermal oxidation of the CO in the flue gas stream in a location external to the boiler. ETO requires heat (1,400 °F to 1,600 °F) and oxygen to convert CO in the flue gas to CO_2. There are two general types of ETO that are used for the control of CO emissions: regenerative thermal oxidization and recuperative thermal oxidization. The primary difference between regenerative and recuperative ETO is that regenerative ETO utilizes a combustion chamber and ceramic heat exchange canisters that are an integral unit, while recuperative ETO utilizes a separate counterflow heat exchanger to preheat incoming air prior to entering the combustion chamber.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable technologies for the control of CO emissions identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on oil-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[179] A technology that has not been demonstrated on oil-fired boilers is considered technically feasible if the technology is both available and

[179] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.

applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Combustion Controls

Combustion controls, which include combustion system design and proper boiler operation and maintenance, are proven technologies for the reduction of CO emissions. These technologies have been widely demonstrated in similar applications to generate significantly lower levels of CO emissions when compared to boilers designed, operated and maintained without regard to CO emissions.

Based on the proven success of this control strategy, combustion controls are considered a demonstrated technology for CO emissions control. Therefore, combustion controls are considered technically feasible.

Flares

Flares are commonly used in the control of organic slipstreams from refineries and other chemical manufacturing processes with sufficient heating value. Flares have not been demonstrated for oil-fired boiler CO emission control. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

The heating value of the auxiliary boiler exhaust is essentially zero, far below the practical operating range for flares (i.e., 300 Btu/scf).[180] Since the auxiliary boiler exhaust will not have sufficient heating value for flaring and since flares have not been applied for oil-fired boiler emissions control, flares are not considered an applicable technology for oil-fired boilers.

As discussed in this section, flares are not applicable for oil-fired boiler CO emissions control. Therefore, flares are determined to be technically infeasible for the auxiliary boiler.

Afterburners

Based on a review of the RBLC database and a survey of air permits for power plants, afterburners are not demonstrated for oil-fired boiler CO control. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

The term “afterburner” is generally appropriate only to describe a thermal oxidizer used to control gases coming from a process where combustion is incomplete.[181] Since the auxiliary boiler will be carefully tuned to maximize fuel combustion efficiency (i.e., subsequently minimizing CO emissions) while minimizing NO_X formation, the process will result in essentially complete combustion. Therefore, additional afterburner combustion would not be expected to provide any useful

[180] U.S. EPA, document no. EPA-452/F-03-019: *Air Pollution Control Technology Fact Sheet - Flares*, p. 2.
[181] U.S. EPA, document no. EPA-452/F-03-022: *Air Pollution Control Technology Fact Sheet - Thermal Incinerator*, p. 1.

benefit, and afterburners are determined to be not applicable for oil-fired boiler CO emissions control.

Since afterburners are not applicable for oil-fired boiler CO emissions control, afterburners are determined to be technically infeasible.

Catalytic Oxidation

Catalytic oxidizers are typically installed to remove CO, VOC, and organic HAP emissions from exhaust streams in the following equipment/processes:

- Surface coating and printing operations;
- Varnish cookers;
- Foundry core ovens;
- Filter paper processing ovens;
- Plywood veneer dryers;
- Gasoline bulk loading stations;
- Chemical process vents;
- Rubber products and polymer manufacturing; and
- Polyethylene, polystyrene, and polyester resin manufacturing.[182]

In a number of cases, catalytic oxidation has been used to control CO and VOC emissions from natural gas-fired combustion turbines since oxidation catalysts are suitable for gas streams with negligible particulate loading. However, based on a review of the RBLC database and power plant air permits, catalytic oxidation is not a demonstrated technology for oil-fired boilers. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

Several factors render CO catalytic oxidation not applicable for oil-fired boilers. First, the particulate loading of the flue gas stream could plug the oxidation catalyst. In addition, trace elements present in oil and the resulting combustion gases (e.g., sulfur in particular[183]) could foul the oxidation catalyst and reduce its effectiveness. Furthermore, SO_2 in the flue gas stream could be oxidized to form SO_3, which could react with the moisture in the flue gas to form sulfuric acid and create a corrosive environment. For these reasons, CO catalytic oxidation is not an applicable technology for oil-fired boilers.

Additionally, catalytic oxidation is not an available technology for the auxiliary boiler. Typical commercially available package catalytic oxidizers can handle exhaust gas flow rates of up to 50,000 scfm,[184] while the auxiliary boiler will have an exhaust flow rate of approximately 70,000 scfm, 40% above the commercially available range for package units. Thus, CO catalytic oxidation is not an available technology for the auxiliary boiler.

182 U.S. EPA, document no. EPA-452/F-03-018: *Air Pollution Control Technology Fact Sheet - Catalytic Incinerator*, p. 3.
183 Ibid.
184 Ibid.

As discussed in this section, catalytic oxidation is not available or applicable. Therefore, catalytic oxidation is determined to be technically infeasible for the auxiliary boiler.

External Thermal Oxidation (ETO)

ETO is generally utilized for controlling CO, VOC, or organic HAP emissions from high-concentration, non-combustion sources (e.g., surface coating operations and chemical plants). Based on a review of the RBLC database and power plant permits, regenerative ETO and recuperative ETO have not been demonstrated for use on an oil-fired boiler. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

ETO is not applicable for auxiliary boiler CO control for the same reason as afterburners. Since the auxiliary boiler will be carefully tuned to maximize fuel combustion efficiency (i.e., subsequently minimizing CO emissions) while minimizing NO_X formation, the process will result in essentially complete combustion. Therefore, additional ETO combustion would not be expected to provide any useful benefit (i.e., the auxiliary boiler serves as a thermal oxidizer where high combustion efficiency is a primary concern), and ETO is determined to be not applicable.

Additionally, the regenerative and recuperative ETO heat exchange systems would be vulnerable to the same sulfur concerns as discussed for CO catalytic oxidation above. SO_2 in the flue gas stream could be oxidized to form SO_3, which could react with the moisture in the flue gas to form sulfuric acid and create a corrosive environment.

For the reasons discussed above, ETO is not applicable. Therefore, ETO is determined to be technically infeasible.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, combustion controls are the only remaining feasible control technology. Table 10.38 ranks the feasible CO control technologies by effectiveness when applied to the Facility.

Table 10.38 - Ranking of CO Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu)
Combustion Controls	0.04

Energy Impacts

Combustion controls are an integral part of the combustion process and are designed to maximize combustion efficiency while maintaining optimal CO and NO_X emissions performance. Thus, combustion controls do not create any energy impacts.

Environmental Impacts

Since maximum fuel combustion efficiency (i.e., minimum CO formation) occurs at the high end of the combustion temperature range, there is a potential for increased NO_X emissions due to thermal NO_X formation. Since NO_X formation is a concern, combustion controls are designed and operated to minimize CO and NO_X formation while maximizing combustion efficiency. Thus, combustion controls do not create any significant environmental impacts.

Economic Impacts

Combustion controls are part of the standard design of modern oil-fired boilers and do not create any economic impacts.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of combustion controls are evaluated below.

Energy Impacts

There are no energy impacts that preclude the selection of combustion controls as CO BACT.

Environmental Impacts

As discussed in Step 3, combustion controls are designed to minimize CO emissions while maintaining an appropriate balance with NO_X formation. There are no environmental impacts that preclude the selection of combustion controls as CO BACT.

Economic Impacts

There are no economic impacts that preclude the selection of combustion controls as CO BACT.

Since there are no energy, environmental, or economic impacts that preclude the use of combustion controls, this technology is selected as CO BACT for the auxiliary boiler.

Step 5 – Select BACT

Based on the analysis presented above, BACT for CO emissions control is the application of combustion controls with an emission limit of 0.04 lb/MMBtu on a 3-hour average basis.

10.6.2 Nitrogen Oxides (NO_X)

NO_X is the term used to collectively refer to NO and NO_2. NO_X is formed by the oxidation of nitrogen contained in the fuel (fuel NO_X) and by the combination of elemental nitrogen and oxygen in the high temperature-environment of the combustion zone (thermal NO_X). Factors affecting the generation of NO_X include flame temperature, residence time, quantity of excess air, and nitrogen content of the fuel.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for NO_X reduction include the use of fuels with lower nitrogen content and combustion control technologies designed to limit the formation of NO_X by controlling the mixing of air and fuel in the combustion zone. These technologies are generally limited in the amount of reduction possible. The potential lower emitting processes/practices are described in more detail below.

Fuel Selection

Nitrogen is contained in fuel oil in low concentrations. Selecting a fuel oil with low nitrogen content could presumably result in the formation of less fuel NO_X.

Low NO_X Burners (LNB)

LNB are designed to limit NO_X formation by controlling the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air, resulting in one or more of the following conditions: (a) reduced oxygen in the primary flame zone; (b) reduced flame temperature; or (c) reduced residence time at peak temperature. Typical low NO_X burner systems incorporate lean combustion (e.g., low excess air) and a secondary burnout zone (e.g., overfire air).[185] Since low NO_X burner designs generally incorporate elements of low excess air and overfire air while achieving better emissions performance than either technology alone, low excess air and overfire air are not considered as separate control options in this analysis.

Water/Steam Injection

Water/steam injection is a lower emitting process/practice that may be used to control the formation of NO_X by lowering the fuel combustion temperature, thus lowering the formation of thermal NO_X.

[185] Air & Waste Management Association, *Air Pollution Engineering Manual, Second Edition* (John Wiley & Sons, Inc., 2000), p. 216.

Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) recirculates a portion of the flue gas with the combustion air, resulting in decreased combustion temperature.[186] Lower combustion temperature reduces the potential for thermal NO_X formation.

Natural Gas Reburning (NGR)

Although typically used for coal-fired boiler retrofit applications only, NGR is evaluated in this analysis for implementation at a new oil-fired unit.

NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, thus creating a secondary combustion zone called the reburn zone. In NGR, the secondary (or reburn) fuel, natural gas, is injected to produce a slightly fuel rich reburn zone. Overfire air is added above the reburn zone to complete burnout of the reburn fuel. As flue gas passes through the reburn zone, part of the NO_X formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) and converted to molecular nitrogen (N_2). While WPEA was unable to locate any oil-fired boiler utilizing NGR, NGR has been reported to achieve NO_X reductions down to 0.16 lb/MMBtu for coal-fired applications.[187]

Fuel-Lean Gas Reburning (FLGR)

Although typically used for coal-fired boiler retrofit applications only, FLGR is evaluated in this analysis for implementation at a new oil-fired unit.

FLGR, also known as controlled gas injection, is a process in which careful injection and controlled mixing of natural gas into the furnace exit region reduces NO_X. The gas is normally injected into a lower temperature zone than in NGR. Whereas NGR requires 15% to 20% of furnace heat input from gas and requires burnout air, the FLGR technology achieves NO_X control using less than 10% gas heat input and no burnout air.[188] Less NO_X reduction is achieved with FLGR when compared with NGR. While WPEA was unable to locate any oil-fired boiler utilizing FLGR, FLGR has been reported to achieve NO_X reductions down to 0.27 lb/MMBtu for coal-fired applications.[189]

Advanced Gas Reburning (AGR)

Although typically used for coal-fired boiler retrofit applications only, AGR is evaluated in this analysis for implementation at a new oil-fired unit.

[186] U.S. EPA, *Nitrogen Oxides (NO_X), Why and How They Are Controlled*, EPA Document No. 456/F-99-006R, November 1999, p. 12.
[187] Folsom, Blair A., Tyson, Thomas J., *Combustion Modification – An Economic Alternative for Boiler NOx Control,* GE Power Systems, April 2001.
[188] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1378.
[189] Northeast States for Coordinated Air Use Management (NESCAUM), Status Report on NO_X: Control Technologies and Cost Effectiveness for Utility Boilers, June 1998.

AGR adds a nitrogen rich compound (typically urea or ammonia) downstream of the reburning zone. The reburning system is adjusted for somewhat lower NO_X reduction to produce free radicals that enhance the selective non-catalytic NO_X reduction. AGR systems can be designed in two ways: (1) non-synergistic, which is essentially the sequential application of NGR and selective non-catalytic reduction (i.e., the nitrogen agent is injected downstream of the burnout air); and (2) synergistic, in which the nitrogen agent is injected with a second burnout air stream. To obtain maximum NO_X reduction and minimum reagent slip in non-synergistic systems, the nitrogen agent must be injected so that it is available for reaction with the furnace gases within a temperature zone around 1,800 °F.[190] While WPEA was unable to locate any oil-fired boiler utilizing AGR, AGR has been reported to achieve NO_X reductions down to 0.12 lb/MMBtu for coal-fired applications.[191]

Amine Enhanced Gas Injection (AEGI)

Although typically used for coal-fired boiler retrofit applications only, AEGI is evaluated in this analysis for implementation at a new oil-fired unit.

AEGI is similar to AGR, except that burn out air is not used, and the selective non-catalytic reduction reagent and reburn fuel are injected to create local, fuel-rich NO_x reduction zones in an overall fuel-lean furnace. The fuel-rich zone exists in local eddies, as in FLGR, with the overall furnace in an oxidizing condition; however the reduction reagent participates with natural gas (or other hydrocarbon fuel) in a NO_x reduction reaction. While WPEA was unable to locate any oil-fired boiler utilizing AEGI, AEGI has been shown to reduce uncontrolled NO_X emissions by 50% to 70% in coal-fired applications (e.g., to 0.15 lb/MMBtu for a boiler with an uncontrolled NO_X emission rate of 0.5 lb/MMBtu).[192]

Selective Catalytic Reduction (SCR)

SCR is a post-combustion NO_X reduction technology in which ammonia is added to the flue gas upstream of a catalyst bed. The ammonia and NO_X react on the surface of the catalyst, forming N_2 and water. SCR reactions occur in a temperature range of 650 °F to 750 °F.[193] Typical catalyst material is titanium dioxide, tungsten trioxide, or vanadium pentoxide.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology in which a reagent (ammonia or urea) is injected into the furnace above the combustion zone, where it reacts with NO_X to reduce it to N_2 and water. Proper flue gas temperature in the injection zone is required for SNCR operation. SNCR reactions are effective in the temperature range

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[190] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1378.

[191] Folsom, B.A., Tyson, T.J., *Combustion Modification – An Economic Alternative for Boiler NOx Control,* GE Power Systems, April 2001, p. 7.

[192] Hall, R.E. and Srivastava, R.K., *An EPA Perspective on Reburn Technology for NO_X Control,* Presented at the 2004 Conference on Reburning for NO_X Control.

[193] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1374.

of 1,800 °F to 2,100 °F.[194] Variations in the operating temperature can result in elevated ammonia slip.

SCONOx

SCONOx is a catalyst technology developed by Goal Line Environmental Technologies. The technology uses a precious metal catalyst to simultaneously convert NO_X and CO to CO_2, H_2O, and N_2. The catalyst must be periodically removed from service for regeneration. This requirement necessitates multiple catalyst sections and additional ductwork and dampers for isolation. Hydrogen diluted with steam is used to regenerate the catalyst and produce a stream of H_2O and N_2 that is vented to the stack.

Electro-Catalytic Oxidation (ECO)

ECO is a multi-pollutant control technology under development by Powerspan Corporation. According to the company's website,[195] ECO is a multi-pollutant control technology that simultaneously controls SO_2, NO_X, Hg, and $PM_{2.5}$. The ECO process is located downstream of a plant's primary particulate removal device (electrostatic precipitator or fabric filter). The process includes a reactor that oxidizes the gaseous pollutants; a scrubber that removes NO_X, SO_2, and the oxidizer reactor products; and a wet electrostatic precipitator that captures the oxidized pollutants.

In 2005, the ECO technology completed a 180-day pilot testing run at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio. The pilot unit processed a flue gas slipstream that represented approximately one-third of the exhaust flow from a 156-MW front wall-fired boiler combusting coal.[196]

Pahlman Process

The Pahlman Process is a multi-pollutant control technology that simultaneously controls NO_X and SO_2. EnviroScrub Technologies, the developer of the Pahlman Process, has released only general information about the technology. According to the company's website, the process is located downstream of the particulate control device and utilizes a spray dryer absorber where a proprietary Pahlmanite™ scrubber material contacts the exhaust stream. The exhaust stream then passes through a "baghouse reaction chamber" where the Pahlmanite™ material is removed prior to the final exhaust stack. This technology is currently in the pilot stage of development, and the company operates a trailer-mounted pilot demonstration unit that can process coal-fired boiler exhaust slip streams of up to 2,000 scfm.[197]

[194] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1373.
[195] http://www.powerspan.com/technology/scrubber_overview.shtml.
[196] http://www.powerspan.com/technology/scrubber_demonstration.shtml.
[197] http://www.enviroscrub.com/pilot.asp, April 27, 2006.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable NO_X control technologies identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on oil-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[198] A technology that has not been demonstrated on oil-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Fuel Selection

While lower nitrogen fuel could presumably result in lower NO_X emissions, fuel oils are categorized by boiling point (e.g., heavy residual vs. light distillate) and sulfur content. Since a supply of low nitrogen fuel oil is not readily available, fuel selection is deemed technically infeasible. However, the facility will utilize ultra low sulfur distillate fuel, which typically contains less nitrogen content as a result of the hydroprocessing conducted during production to remove sulfur from the fuel.[199]

Low NO_X Burners (LNB)

LNB are a proven technology for minimizing NO_X emissions and are considered technically feasible. Due to their demonstrated effectiveness and reliability, low NO_X burners have become part of the standard design for modern boiler systems. Thus, low NO_X burners are considered the base case for this analysis.

Water/Steam Injection

Water/steam injection is not incorporated into modern burner/boiler design. Modern boilers utilize a water-cooled firebox lacking sufficient physical space for water injection.[200] Current state-of-the-art units equipped with low NO_X burners achieve low NO_X levels without the water[201] and energy requirements associated with water/steam injection. Since the auxiliary boiler will include modern low-NO_X burner technology, obsolete water/steam injection is considered infeasible and is not considered further.

Flue Gas Recirculation (FGR)

FGR is a proven technology for minimizing NO_X emissions and is considered technically feasible.

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[198] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.
[199] U.S. EPA, 66 FR 35379, July 5, 2001.
[200] Telephone conversation between Mr. John English, English Boiler Company, and Mr. David Wilson, LS Power Development, LLC, July 25, 2006. Additionally, steam or water injection is not applicable when firing oil per correspondence from Mr. Daniel Poupart, National Combustion Equipment, Inc., July 25, 2006.
[201] While not related to the technical feasibility discussion, the water consumption associated with water / steam injection would represent a negative environmental impact in the arid region if water / steam injection were feasible.

Reburning Technologies (NGR, FLGR, AGR, and AEGI)

While reburning technologies have been applied as a retrofit technology to large coal-fired boilers, reburning technology is not applied to new oil-fired boilers. Modern oil-fired boiler designs maximize combustion efficiency and minimize NO_X formation without the use of reburning. Thus, reburning is not an option offered on new oil-fired boilers.[202] Since reburn technologies are not considered as available for new oil-fired boilers, the reburn technolgoies are determined to be technically infeasible.[203]

Selective Catalytic Reduction (SCR)

Although WPEA is not aware of any application of SCR for a distillate-fired boiler, SCR has been applied to other types of combustion sources and is considered technically feasible.

Selective Non-Catalytic Reduction (SNCR)

To remove NO_X efficiently and without significant reagent slip, the SNCR reagent must be injected at a location in the exhaust path meeting specific temperature requirements. Thus, it is not feasible to apply selective non-catalytic reduction to boilers that have high turndown capabilities and modulate frequently.[204] WPEA plans to operate the auxiliary boiler only for brief periods during startup of the PC-fired boilers. Since the auxiliary boiler exhaust will not operate at steady state for long periods of time, SNCR would not be expected to operate efficiently and without undesirable reagent slip. Thus, SNCR is considered technically infeasible.

SCONOx

SCONOx is not a demonstrated technology for controlling NO_X emissions from oil-fired boilers. Therefore, an assessment of the availability and applicability is conducted to determine if the technology is technically feasible.

The manufacturer of this technology does not list oil-fired boilers as an available application for the technology. Therefore, SCONOx is not considered available for the auxiliary boiler.

Additionally, the presence of sulfur in the exhaust has the potential to poison the SCONOx catalyst, limiting its effectiveness and useful life. Furthermore, the particulate loading in the exhaust stream could foul the catalyst, rendering it ineffective. Therefore, SCONOx is not applicable for oil-fired boiler NO_X control.

Since this technology is not available and not applicable for oil-fired boiler NO_X control, SCONOx is determined to be technically infeasible.

[202] Telephone conversation between Mr. John English, English Boiler Company, and Mr. David Wilson, LS Power Development, LLC, July 25, 2006.
[203] Additionally, while not related to technical feasibility, there is currently not a supply of natural gas available at the WPEA site. Constructing approximately 90 miles of natural gas pipeline to support reburning would be cost prohibitive even if the reburn technologies were technically feasible.
[204] Cleaver-Brooks, *Boiler Emissions Reference Guide, Second Edition*, p. 12.

Electro-Catalytic Oxidation (ECO)

To date, the only application of this technology has been a pilot facility for a coal-fired boiler.[205] This technology has not been demonstrated use on an oil-fired boiler, and the company does not list oil-fired units as a potential application for the technology. Thus, ECO is not considered available for the auxiliary boiler. Therefore, the ECO technology is determined to be technically infeasible.

Pahlman Process

Per the manufacturer, the Pahlman process has been field-tested on units firing solid fuels only.[206] Since the technology has not been applied to oil-fired units, the Pahlman process is not considered available for the auxiliary boiler.

Additionally, the Pahlman Process is still in the pilot stage of development. The company has tested a trailer-mounted demonstration system capable of treating up to 2,000 scfm of flue gas, but the trailer-mounted system is considered a pilot system only.[207] Since the Pahlman Process has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available. Therefore, the Pahlman Process is determined to be technically infeasible.

In summary, the technically feasible technologies identified for the control of NO_X emissions are:

- Selective catalytic reduction (SCR)
- Flue gas recirculation (FGR)
- Low NO_X burners (LNB)

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Since LNB have become a standard component of boiler design, the emissions associated with LNB are considered to be the baseline. Since LNB, FGR, and SCR are compatible technologies, the most effective combinations of these technologies are evaluated. Table 10.39 lists the control efficiency of each feasible technology in order of effectiveness.

[205] http://www.powerspan.com/technology/scrubber_demonstration.shtml.
[206] http://www.enviroscrub.com/field.asp.
[207] Ibid.

Table 10.39 – Control Efficiencies for NO_X Technologies

Control Technology	Efficiency
SCR + FGR + LNB	70% to 90%
FGR + LNB	50% to 80%
LNB	30% to 50%

Energy Impacts

This subsection presents the energy impacts of the feasible NO_X control options. The energy impacts for the NO_X control options are presented in Table 10.40.

Table 10.40 – Summary of Energy Impacts for NO_X Control Options

Control Option	Energy Impacts
SCR + FGR + LNB	Additional energy required to run SCR equipment, vaporize ammonia, and power fan due to increased pressure drop. Energy required to recirculate flue gas.
FGR + LNB	Energy required to recirculate flue gas.
LNB	Baseline

Environmental Impacts

This subsection lists the environmental impacts of the feasible NO_X control options. A summary of the environmental impacts is included in Table 10.41 below.

Table 10.41 – Summary of Environmental Impacts for NO_X Control Options

Control Option	Environmental Impacts
SCR + FGR + LNB	SCR would require the storage and use of ammonia. Might trigger OSHA and Community Right-to-Know Act requirements. Ammonia slip (i.e., unreacted ammonia emitted from the stack) would occur. Would create catalyst disposal waste periodically.
FGR + LNB	Not expected to create environmental impacts.
LNB	Baseline

Economic Impacts

Per EPA's Draft NSR Manual, average and incremental cost effectiveness are the two economic criteria considered in Step 3 of the BACT analysis.[208] A summary of the economic impacts analysis is included in Table 10.42 below. Table 10.43 provides additional details of the analysis.

Table 10.42 – Summary of Economic Impacts for NO_X Control Options

Control Option	Emissions (lb/hr)	Emissions (tpy)	Total Annualized Cost over Baseline ($/year)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
SCR + FGR + LNB	9.18	2.29	$1,596,000	$136,294	$231,640
FGR + LNB	37	9.18	$2,800	$581	$581
LNB (Baseline)	53	14	--	--	--

Notes: FGR assumes 30% additional removal over LNB.
SCR assumes 75% additional removal over FGR + LNB.

[208] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.31.

Table 10.43 – Detail of Economic Impacts for NO_X Control Options

Parameter	FGR+LNB	SCR + FGR+LNB	Notes
Heat Input, MMBtu/hr	367	367	
NO_X Emission Rate, lb/MMBtu	0.15	0.15	
Baseline NO_X emissions, tpy	14	14	
Removal	30%	83%	
Emission Rate, lb/MMBtu	0.1	0.025	
Direct capital costs	$15,000	$700,000	(1)
Indirect capital costs	$3,000	$294,000	(2)
Total Capital Cost	$21,000	$2,066,000	
Annual costs			
Lost energy	--	$1,311,000	(3)
Ammonia	--	$9,000	
Catalyst Replacement	--	$4,000	
Maintenance material	$300	$31,000	(4)
Capital recovery	$2,500	$241,000	
Total annual costs	$2,800	$1,596,000	
Incremental costs	$2,800	$1,593,200	
NO_X emissions, tpy	9.18	2.29	
Cost effectiveness, $/ton	$581	$136,294	
Incremental removal, tpy	4.82	6.89	
Incremental cost, $/ton	$581	$231,640	

Notes:

(1) Direct capital costs uses EPA factor of $4,000/MMBtu/hr from p. 2-3 of Cost Control Manual.

(2) Based on methodology in EPA Cost Control Manual, EPA-452-02-001. Includes engineering, contingency, general facilities, and preproduction costs.

(3) Lost energy caused by electrical power consumption for SCR equipment, ammonia vaporization, and additional fan power.

(4) Maintenance material equal to 1.5% of total capital costs.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the control technologies are evaluated below, starting with the most effective control.

SCR + FGR + LNB

A case-by-case consideration of energy, environmental, and economic impacts for SCR + FGR + LNB is presented below.

Energy Impacts

As discussed in Step 3, SCR would utilize energy to operate the SCR equipment, vaporize ammonia, and overcome the pressure drop of the system. These energy requirements represent an adverse energy impact.

Environmental Impacts

As shown in Step 3, SCR would utilize ammonia and create a catalyst disposal waste stream. Ammonia use and catalyst operations could result in adverse environmental impacts.

Economic Impacts

As shown in Step 3, the average cost of controlling NO_X with SCR + FGR + LNB is $136,294 per ton. The incremental cost is $231,640 per ton. These costs are extremely high and represent a significant negative economic impact.

Based on the energy, environmental, and significant economic impacts, the SCR + FGR + LNB technology combination is not selected as BACT. Since this option is not selected as BACT, the next most effective technology is evaluated.

FGR + LNB

A case-by-case consideration of energy, environmental, and economic impacts for FGR + LNB is presented below.

Energy Impacts

As discussed in Step 3, FGR would utilize a nominal amount of energy to recirculate the flue gas and overcome the pressure drop of the system. These energy impacts are not expected to be significant.

Environmental Impacts

As shown in Step 3, the use of FGR + LNB is not expected to create any adverse environmental impacts.

Economic Impacts

As shown in Step 3, the average and incremental cost of controlling NO_X with FGR + LNB is $581 per ton. This cost is not a significant economic impact.

Since there are no energy, environmental, or economic impacts that preclude the use of FGR + LNB, this technology combination is selected as NO_X BACT for the auxiliary boiler.

Step 5 – Select BACT

Based on the preceding analysis, BACT for NO_X emission control is the use of FGR + LNB with an emission limit of 0.1 lb/MMBtu on a 3-hour average basis.

10.6.3 Sulfur Dioxide (SO_2)

SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. While the SO_2 generally remains in a gaseous phase throughout the flue gas flow path, a small portion of the SO_2 may be oxidized to SO_3. The SO_3 can subsequently combine with water vapor to form H_2SO_4.

<u>Step 1 – Identify All Control Technologies</u>

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for control of SO_2 emissions are pre-combustion technologies that have the potential to result in lower levels of SO_2 emissions. Lower emitting processes/practices include the following:

<u>Fuel Selection</u>

Oil-fired boiler SO_2 emissions result from the oxidation of sulfur contained in the oil during the combustion process. Therefore, the potential for SO_2 formation can be reduced by firing oil with a low sulfur content. Modern low sulfur oils (e.g., ultra low sulfur distillate with sulfur content of 0.0015% by weight) will be available to minimize the amount of SO_2 formed during combustion. Since this fuel will be available and results in virtually negligible SO_2 emissions, the use of ultra low sulfur distillate oil is considered the baseline for the remainder of this analysis.

Add-On Controls

Due to the use of ultra low sulfur distillate fuel, the SO_2 concentration in the auxiliary boiler exhaust will be extremely low (i.e., less than 1 ppmv). Based on a review of the RBLC database, permits for other power plants, and discussions with vendors, no add-on SO_2 controls have been installed on a boiler firing ultra low sulfur distillate fuel, and no add-on controls have been demonstrated as available for reducing emissions below ultra low sulfur distillate baseline emissions level. Thus, consistent with EPA guidance,[209] add-on controls are not considered in this analysis.

<u>Step 2 – Eliminate Technically Infeasible Options</u>

In this step, the potentially applicable SO_2 control technologies identified in Step 1 are evaluated for technical feasibility. Fuel selection (i.e., the use of low sulfur fuels) is widely used to minimize SO_2 emissions and is considered technically feasible.

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[209] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.73. The example illustrates that EPA does not expect analysis of add-on controls when the emission rate with a clean-burning fuel is on the same order as other sources controlled with stringent add-on controls.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Table 10.44 ranks the feasible SO_2 control technologies by effectiveness for the auxiliary boiler.

Table 10.44 - Ranking of SO_2 Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu)
Ultra Low Sulfur Distillate Fuel [(1)]	1.6×10^{-3}

Notes:
(1) Control effectiveness based on ultra low sulfur distillate fuel with a sulfur content of 15 ppm by weight or less.

Energy Impacts

Ultra low sulfur distillate fuel has a heating value of 19,200 Btu/lb and does not present any energy impacts.

Environmental Impacts

As with any liquid fuel, the ultra low sulfur distillate fuel is stored in a storage tank prior to use. WPEA will apply BACT to minimize emissions from the fuel storage tank.

Economic Impacts

Although ultra low sulfur distillate fuel may present a higher cost than lower-grade distillate fuels, economic impacts are not calculated since ultra low sulfur distillate fuel is considered the base case.

Step 4 – Evaluate Most Effective Controls and Document Results

Step 4 evaluates the energy, environmental and economic impacts of ultra low sulfur distillate fuel for minimizing SO_2 emissions from the auxiliary boiler.

Energy Impacts

As discussed in Step 3, there are no energy impacts associated with ultra low sulfur distillate fuel.

Environmental Impacts

The environmental impacts associated with a fuel storage tank are minimal and do not preclude the use of ultra low sulfur distillate fuel as BACT.

Economic Impacts

While there may be a higher cost associated with the use of ultra low sulfur distillate fuel, this potential economic impact does not preclude the use of this fuel as BACT.

Since there are no energy, environmental, or economic impacts that preclude the use of ultra low sulfur distillate, this technology is selected as SO_2 BACT for the auxiliary boiler.

Step 5 – Select BACT

Based on the above analysis, BACT for SO_2 emissions is the use of ultra low sulfur distillate fuel (≤15 ppm sulfur) with an emission limit of 1.6×10^{-3} lb/MMBtu on a 3-hour average basis.

10.6.4 Particulate Matter (PM / PM_{10})

Filterable particulate matter emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. The PM emitted by distillate oil-fired boilers is primarily composed of carbonaceous particles resulting from incomplete combustion of oil and is not correlated to the ash or sulfur content of the oil.[210]

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for control of PM/PM_{10} emissions are pre-combustion technologies that have the potential to result in lower levels of particulate formation. Lower emitting processes/practices include the following:

Fuel Selection

The only potentially applicable lower emitting process/practice is the use of distillate fuel. As discussed above, combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils.

Add-On Controls

Fabric Filter Baghouse

A fabric filter baghouse removes particles from the flue gas by drawing dust-laden flue gas and condensables through a bank of filter tubes suspended in a housing. A filter cake, composed of the removed particulate, builds up on the dirty side of the bag. Periodically, the cake is removed through physical mechanisms (e.g., blast of compressed air from the clean side of the bag, mechanical shaking of the bags, etc.) which causes the cake to fall. The dust is then collected in a hopper and removed.

Electrostatic Precipitator (ESP)

An electrostatic precipitator (ESP) removes particles from the flue gas by charging the particles inductively with an electric field and then attracting the particles to highly charged collector plates, from which they are removed. An ESP consists of a hopper-bottomed box containing rows of plates forming passages through which the flue gas flows. Centrally located in each passage are emitting electrodes energized with a high-voltage, negative polarity direct current. The voltage applied is high enough to ionize the gas molecules close to the electrodes, resulting in a corona current of gas ions from the emitting electrodes across the gas passages to the grounded collecting plates. When passing through the flue gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The

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[210] U.S. EPA, AP-42, Fifth Edition, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*, Section 1.3.3.1, September 1998.

electric field forces the charged particles out of the gas stream towards the grounded plates, and there they collect in a layer. The plates are periodically cleaned by a rapping system to release the ash layer into ash hoppers as an agglomerated mass.

Wet Electrostatic Precipitator (WESP)

A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP: charging, collection, and removal. Unlike with a dry ESP, however, with a WESP, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid, rather than mechanically rapping the collector plates. WESPs are more widely used in applications where the gas stream has a high moisture content, is below the dew point, or includes sticky particulate.

Wet Scrubber

Wet scrubbers achieve particulate removal through liquid-to-gas contact. In a spray tower scrubber, the particulate-laden stream is introduced into a chamber where it contacts the liquid droplets generated by the spray nozzles. Particulate removal is accomplished via physical absorption of the particles into the liquid droplets. The size of the droplets generated by the spray nozzles is controlled to maximize liquid-particle contact and, consequently, scrubber collection efficiency.[211]

Venturi Scrubber

In a venturi scrubber, dust-laden gases are wetted continuously at the venturi throat. Flowing at 12,000 to 18,000 feet per minute, the high-velocity gases produce a shearing force on the scrubbing liquid due to the initial high velocity differential between the two steams. This shearing force causes the liquid to become atomized into very fine droplets. Impaction takes place between the dust entrained in the gas stream and the liquid droplets. As the gas decelerates, collision continues and agglomerated dust-laden liquor droplets discharge through a diffuser into the lower chamber of a separator vessel. Impingement of the stream into the liquid reservoir removes most of the particulate.

Electro-Catalytic Oxidation (ECO)

ECO is a multi-pollutant control technology under development by Powerspan Corporation. According to the company's website,[212] ECO is a multi-pollutant control technology that simultaneously controls SO_2, NO_X, Hg, and $PM_{2.5}$. The ECO process must be located downstream of a plant's primary particulate removal device (electrostatic precipitator or fabric filter). The ECO technology achieves particulate reduction via a WESP integrated in the tail end of the process.

In 2005, the ECO technology completed a 180-day pilot testing run at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio. The pilot unit processed a flue gas slipstream

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[211] U.S. EPA, document no. EPA-452/F-03-016: *Air Pollution Control Technology Fact Sheet – Spray-Chamber/Spray-Tower Wet Scrubber*, p. 3.
[212] http://www.powerspan.com/technology/scrubber_overview.shtml.

that represented approximately one-third of the exhaust flow from a 156-MW front wall-fired boiler combusting coal.[213]

Note that a centrifugal separator (cyclone) is not listed as a potential technology for oil-fired boilers since cyclones are typically only used first-stage particulate removal for solid fuel-fired boilers, which produce a large amount of coarse particles compared to oil-fired boilers.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable particulate control technologies identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on oil-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[214] A technology that has not been demonstrated on oil-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Fuel Selection

As discussed above, properly operated boilers firing light distillate oils emit inherently low levels of particulate. Thus, fuel selection is considered technically feasible and serves as the base case for the remainder of this analysis.

Fabric Filter Baghouse

The fabric filter baghouse is a proven technology for the control of particulate emissions; however, some studies and data show that oil mist carryover can foul the bags, shortening filter bag lifespan and efficiency. Nonetheless, this technology has been widely demonstrated on solid fuel-fired units and is therefore considered technically feasible.

Electrostatic Precipitator

The ESP is a proven technology for the control of particulate emissions. This technology has been widely demonstrated and is considered technically feasible.

Wet Electrostatic Precipitator

The WESP is a proven technology for the control of particulate emissions. This technology has been demonstrated and is considered technically feasible.

Wet Scrubber

Wet scrubbers are a proven technology for the control of particulate emissions. Wet scrubbers have been demonstrated and are considered technically feasible.

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213 http://www.powerspan.com/technology/scrubber_demonstration.shtml.
214 U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.

Venturi Scrubber

Venturi scrubbers are a proven technology for the control of particulate emissions. Venturi scrubbers have been demonstrated and are considered technically feasible.

Electro-Catalytic Oxidation (ECO)

To date, the only application of this technology has been a pilot facility processing a flue gas slip stream from a boiler firing Eastern bituminous coal.[215] This technology has not been applied to an oil-fired boiler. Since the ECO technology has not been developed for oil-fired boiler combustion, this technology is not considered available. Therefore, the ECO technology is determined to be technically infeasible.

In summary, the technically feasible control technologies identified for the control of PM/PM_{10} emissions are:

- Fabric Filter Baghouse
- Electrostatic Precipitator (ESP)
- Wet Electrostatic Precipitator (WESP)
- Wet Scrubber
- Venturi Scrubber

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. Table 10.45 ranks the feasible particulate control technologies by effectiveness when applied to the Facility.

[215] http://www.powerspan.com/technology/scrubber_demonstration.shtml.

Table 10.45 – Ranking of Particulate Control Technologies by Effectiveness

Control Technology	Control Efficiency (%)	Control Effectiveness (lb/MMBtu) [1]
Fabric Filter Baghouse	99.5%	5.0×10^{-5}
Electrostatic Precipitator	99%	1.0×10^{-4}
Wet Electrostatic Precipitator	99%	1.0×10^{-4}
Wet Scrubber	95%	5.0×10^{-4}
Venturi Scrubber	95%	5.0×10^{-4}
Fuel Selection: Distillate Fuel	Baseline	0.01

Notes:
(1) Represents filterable particulate as measured using EPA Method 5.

A review of the available technical literature and information was conducted in order to establish the effectiveness of each technically feasible control technology. This included review of technical papers, vendor publications, reference books, the RBLC database and BACT studies for similar oil-fired auxiliary boilers.

Energy Impacts

This subsection lists the energy impacts of the remaining particulate control options. One energy impact associated each technologies is pressure drop, which increases the energy required to operate the system. For the ESP technologies, another energy impact is the electric power required to impart an electric charge on the entrained particulate. The energy impacts for the particulate control options are presented in Table 10.46.

Table 10.46 – Summary of Energy Impacts for Particulate Control Options

Control Option	Typical Pressure Drop (atm) (1)	Power Required to Operate ESP (kW)
Fabric Filter Baghouse	0.01 to 0.02 (1)	N/A
Electrostatic Precipitator	0.001 (1)	117 (2)
Wet Electrostatic Precipitator	0.001 (1)	117 (2)
Wet Scrubber	0.004 (3)	N/A
Venturi Scrubber	0.02 (4)	N/A

Notes:

(1) Based on EPA Clean Air Technology Center (CATC) control technology factsheets.

(2) Based on a corona power of 800 Watts per 1,000 acfm per the EPA Air Pollution Training *Institute's ESP Design Parameters and Their Effects on Collection Efficiency*.

(3) Typical pressure drop obtained from Utah Department of Environmental Quality Intent to Approve No. DAQE-IN1743011-06, May 9, 2006.

(4) Typical minimum pressure drop based on vendor data.

Environmental Impacts

Particulate control devices remove the particulate from the exhaust stream. One environmental concern is proper disposal of the particulate collected. Another concern for the wet technologies is the wastewater created by the control device. The environmental impacts of the particulate control devices are listed in Table 10.47.

Table 10.47 – Summary of Environmental Impacts for Particulate Control Options

Control Option	Impact
Fabric Filter Baghouse	Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations. Filter bags would be replaced and disposed of as needed.
Electrostatic Precipitator	Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations.
Wet Electrostatic Precipitator	Wastewater stream would have to be treated in accordance with applicable regulations. Collected waste products would have to be periodically removed and disposed of in accordance with applicable regulations.
Wet Scrubber	Wastewater stream would have to be treated in accordance with applicable regulations. Collected waste products would have to be removed and disposed of in accordance with applicable regulations.
Venturi Scrubber	Wastewater stream would have to be treated in accordance with applicable regulations. Collected waste products would have to be removed and disposed of in accordance with applicable regulations.

Economic Impacts

Economic impacts for the add-on control technologies are presented in Table 10.48 and Table 10.49 below.

Table 10.48 – Summary of Economic Impacts for PM_{10} Control Options

Control Option	Emissions (lb/hr)	Emissions (tpy)	Total Annualized Cost ($/year)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Fabric Filter Baghouse	0.0018	0.0046	$615,000	$671,837	--
WESP	0.037	0.0092	$3,743,000	$4,109,574	--
ESP	0.037	0.0092	$2,597,000	$2,851,339	$70,570,652
Venturi Scrubber	0.18	0.046	$326,000	$372,998	--
Wet Scrubber	0.18	0.046	$170,000	$194,508	$194,508
Baseline	3.67	0.92	--	--	--

Table 10.49 – Detail of Economic Impacts Analysis for PM/PM_{10} Control Options

Parameter	Wet Scrubber	Venturi Scrubber	ESP	WESP	Baghouse
Heat Input, MMBtu/hr	367	367	367	367	367
PM_{10} Emission Rate, lb/MMBtu (filterable)	0.01	0.01	0.01	0.01	0.01
Baseline PM_{10} emissions, tpy	0.92	0.92	0.92	0.92	0.92
Removal	95%	95%	99%	99%	99.5%
Emission Rate, lb/MMBtu	5.0×10^{-4}	5.0×10^{-4}	1.0×10^{-4}	1.0×10^{-4}	5.0×10^{-5}
Purchased equipment costs (1)	$415,000	$825,000	$7,379,000	$10,603,000	$1,849,000
Total capital investment	$793,000	$1,577,000	$16,528,000	$23,751,000	$4,013,000
Utilities	$13,000	$21,000	$35,000	$53,000	$39,000
Total annual costs	$170,000	$326,000	$2,597,000	$3,743,000	$615,000
PM_{10} emissions, tpy	0.046	0.046	0.0092	0.0092	0.0046
Removal, tpy	0.87	0.87	0.911	0.911	0.915
Control cost, $/ton	194,508	372,998	2,851,339	4,109,574	671,837

Notes:

(1) Costs estimated using Version 7.5 of EPA's Air Compliance Advisor program.

<u>Step 4 – Evaluate Most Effective Controls and Document Results</u>

The potential energy, environmental, and economic impacts of the control technologies are evaluated below, starting with the most effective control.

<u>Fabric Filter Baghouse</u>

A case-by-case consideration of energy, environmental, and economic impacts for a fabric filter baghouse is presented below.

<u>Energy Impacts</u>

As discussed in Step 3, a baghouse would require additional auxiliary power to overcome the draft loss across the fabric filter bags. These energy requirements represent a nominal adverse energy impact.

<u>Environmental Impacts</u>

As shown in Step 3, use of a baghouse would create a solid waste stream. The solid waste stream would represent a nominal adverse environmental impact.

Economic Impacts

As shown in Step 3, the average cost of controlling particulate with a fabric filter baghouse is $671,837 per ton. This cost is extremely high and represents a significant negative economic impact.

Based on the combination of the energy, environmental, and significant economic impacts, fabric filter baghouse technology is not selected as BACT. Since a fabric filter baghouse is not selected as BACT, the next most effective technology is evaluated.

Electrostatic Precipitator (ESP)

A case-by-case consideration of energy, environmental, and economic impacts for an ESP is presented below.

Energy Impacts

As discussed in Step 3, an ESP would require significant corona power to remove the particulate. This energy requirement represents an adverse energy impact.

Environmental Impacts

As shown in Step 3, use of an ESP would create a solid waste stream. The solid waste stream would represent a nominal adverse environmental impact.

Economic Impacts

As shown in Step 3, the average cost of controlling particulate with an ESP is $2,851,339 per ton. This cost is extremely high and represents a significant negative economic impact.

Based on the combination of the energy, environmental, and significant economic impacts, ESP technology is not selected as BACT. Since an ESP is not selected as BACT, the next most effective technology is evaluated.

Wet Electrostatic Precipitator (WESP)

A case-by-case consideration of energy, environmental, and economic impacts for a WESP is presented below.

Energy Impacts

As discussed in Step 3, a WESP would require significant corona power to remove the particulate. This energy requirement represents an adverse energy impact.

Environmental Impacts

As shown in Step 3, use of a WESP would create both a liquid and a solid waste stream. These waste streams would represent an adverse environmental impact.

Economic Impacts

As shown in Step 3, the average cost of controlling particulate with a WESP is $4,109,574 per ton. This cost is extremely high and represents a significant negative economic impact.

Based on the combination of the energy, environmental, and significant economic impacts, WESP technology is not selected as BACT. Since a WESP is not selected as BACT, the next most effective technology is evaluated.

Wet Scrubber

A case-by-case consideration of energy, environmental, and economic impacts for a wet scrubber is presented below.

Energy Impacts

As discussed in Step 3, a wet scrubber would require additional auxiliary power to overcome the draft loss across the scrubber. These energy requirements represent a nominal adverse energy impact.

Environmental Impacts

As shown in Step 3, use of a wet scrubber would create both a liquid and a solid waste stream. These waste streams would represent an adverse environmental impact.

Economic Impacts

As shown in Step 3, the average cost of controlling particulate with a wet scrubber is $194,508 per ton. This cost is extremely high and represents a significant negative economic impact.

Based on the combination of the energy, environmental, and significant economic impacts, wet scrubber technology is not selected as BACT. Since a wet scrubber is not selected as BACT, the next most effective technology is evaluated.

Venturi Scrubber

A case-by-case consideration of energy, environmental, and economic impacts for a venturi scrubber is presented below.

Energy Impacts

As discussed in Step 3, a venturi scrubber would require additional auxiliary power to overcome the draft loss across the scrubber. These energy requirements represent a nominal adverse energy impact.

Environmental Impacts

As shown in Step 3, use of a venturi scrubber would create both a liquid and a solid waste stream. These waste streams would represent an adverse environmental impact.

Economic Impacts

As shown in Step 3, the average cost of controlling particulate with a venturi scrubber is $372,998 per ton. This cost is extremely high and represents a significant negative economic impact.

Based on the combination of the energy, environmental, and significant economic impacts, venturi scrubber technology is not selected as BACT. Since a venturi scrubber is not selected as BACT, the next most effective technology is evaluated.

Fuel Specification

A case-by-case consideration of energy, environmental, and economic impacts for the use of distillate fuel is presented below.

Energy Impacts

The use of distillate fuel would not create any negative energy impacts.

Environmental Impacts

Distillate fuel represents the base case for the auxiliary boiler design and does not create adverse environmental impacts.

Economic Impacts

Distillate fuel represents the base case for the auxiliary boiler design and does not create adverse economic impacts.

Since there are no energy, environmental, or economic impacts that preclude the use of distillate fuel, this technology is selected as PM/PM_{10} BACT for the auxiliary boiler.

Step 5 – Select BACT

Based on the preceding analysis, BACT for PM/PM_{10} emission control is the use of ultra low sulfur distillate fuel with a filterable emission limit of 0.01 lb/MMBtu and a total emission limit of 0.05 lb/MMBtu, each on a 3-hour average basis.

10.6.5 Volatile Organic Compounds (VOC)

Combustion is a thermal oxidation process in which carbon and hydrogen contained in a fuel combine with oxygen in the combustion zone to form CO_2 and H_2O. VOC is emitted from the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel. Properly designed and operated boilers typically emit low levels of VOC. High levels of VOC emissions could result from poor burner design or sub-optimal firing conditions.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for VOC emissions control are combustion control techniques that maximize the thermal oxidation of carbon to minimize the formation of VOC. Lower emitting processes/practices include the following:

Combustion Controls

Optimization of the design, operation, and maintenance of the combustion system is the primary mechanism available for lowering VOC emissions. This process is often referred to as combustion controls. The combustion system design on modern oil-fired boilers provides all of the factors required to facilitate complete combustion. These factors include continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber. As a result, a properly designed furnace/combustion system is effective at limiting VOC formation by maintaining the optimum furnace temperature and amount of excess oxygen.

Unfortunately, the addition of excess air and maintenance of high combustion temperatures for control of VOC emissions may lead to increased NO_X emissions. Consequently, typical practice is to design the combustion system (specifically, the air/fuel mixture and temperature) such that VOC emissions are reduced as much as possible without causing NO_X levels to significantly increase.

Proper operation and maintenance of the combustion system helps to minimize the formation and emission of VOC by ensuring that the combustion system operates as designed. This includes maintaining the air/fuel ratio at the specified design point, having the proper air and fuel conditions at the burner, and maintaining the combustion air control system in proper working condition.

Add-On Controls

Potential add-on controls for the auxiliary boiler include the following:

Flares

Flares are commonly used in the control of organic-laden slipstreams from refineries and other chemical manufacturing processes with sufficient heating value. A flare operates by continuously maintaining a pilot flame that is typically maintained by natural gas. When a combustible exhaust stream is vented to a flare, the exhaust stream is ignited by the pilot flame at the flare tip, and combustion occurs in the ambient air above the flare.

Afterburning

Afterburners convert VOC into CO_2 by utilizing simple gas burners to bring the temperature of the exhaust stream up to 1,400 °F to promote complete combustion. Operation of afterburners would require significant amounts of natural gas.

Catalytic Oxidation

A catalytic oxidizer converts the VOC in the combustion gases to CO_2 at temperatures ranging from 500 °F to 700 °F in the presence of a catalyst. Catalytic oxidizers are susceptible to fine particles suspended in exhaust gases that can foul and poison the catalyst. Catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device; however, this would require reheating the exhaust gases to the required operating temperature for the catalytic process.

External Thermal Oxidation (ETO)

ETO promotes thermal oxidation of the VOC in the flue gas stream in a location external to the boiler. ETO requires heat (1,400 °F to 1,600 °F) and oxygen to convert VOC in the flue gas to CO_2. There are two general types of ETO that are used for the control of VOC emissions: regenerative thermal oxidization and recuperative thermal oxidization. The primary difference between regenerative and recuperative ETO is that regenerative ETO utilizes a combustion chamber and ceramic heat exchange canisters that are an integral unit, while recuperative ETO utilizes a separate counterflow heat exchanger to preheat incoming air prior to entering the combustion chamber.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable technologies for the control of VOC emissions identified in Step 1 are each evaluated for technical feasibility. Per EPA's Draft NSR Manual, control technologies that have been installed and operated successfully on oil-fired boilers are "demonstrated" and are considered technically feasible unless there are source-specific factors that justify technical infeasibility.[216] A technology that has not been demonstrated on oil-fired boilers is considered technically feasible if the technology is both available and applicable (see Section 10.2 of this document). Technologies that are not available or not applicable are considered technically infeasible.

Combustion Controls

Combustion controls, which include combustion system design and proper boiler operation and maintenance, are proven technologies for the reduction of VOC emissions. These technologies have been widely demonstrated in similar

[216] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.17.

applications to generate significantly lower levels of VOC emissions when compared to boilers designed, operated and maintained without regard to VOC emissions.

Based on the proven success of this control strategy, combustion controls are considered a demonstrated technology for VOC emissions control. Therefore, combustion controls are considered technically feasible.

Flares

Flares are commonly used in the control of organic slipstreams from refineries and other chemical manufacturing processes with sufficient heating value. Flares have not been demonstrated for oil-fired boiler VOC emission control. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

The heating value of the auxiliary boiler exhaust is essentially zero, far below the practical operating range for flares (i.e., 300 Btu/scf).[217] Since the auxiliary boiler exhaust will not have sufficient heating value for flaring and since flares have not been applied for oil-fired boiler emissions control, flares are not considered an applicable technology for oil-fired boilers.

As discussed in this section, flares are not applicable for oil-fired boiler VOC emissions control. Therefore, flares are determined to be technically infeasible for the auxiliary boiler.

Afterburners

Based on a review of the RBLC database and a survey of air permits for power plants, afterburners are not demonstrated for oil-fired boiler VOC control. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

The term "afterburner" is generally appropriate only to describe a thermal oxidizer used to control gases coming from a process where combustion is incomplete.[218] Since the auxiliary boiler will be carefully tuned to maximize fuel combustion efficiency (i.e., subsequently minimizing VOC emissions) while minimizing NO_X formation, the process will result in essentially complete combustion. Therefore, additional afterburner combustion would not be expected to provide any useful benefit, and afterburners are determined to be not applicable for oil-fired boiler VOC emissions control.

Since afterburners are not applicable for oil-fired boiler VOC emissions control, afterburners are determined to be technically infeasible.

[217] U.S. EPA, document no. EPA-452/F-03-019: *Air Pollution Control Technology Fact Sheet - Flares*, p. 2.

[218] U.S. EPA, document no. EPA-452/F-03-022: *Air Pollution Control Technology Fact Sheet - Thermal Incinerator*, p. 1.

Catalytic Oxidation

Catalytic oxidizers are typically installed to remove CO, VOC, and organic HAP emissions from exhaust streams in the following equipment/processes:

- Surface coating and printing operations;
- Varnish cookers;
- Foundry core ovens;
- Filter paper processing ovens;
- Plywood veneer dryers;
- Gasoline bulk loading stations;
- Chemical process vents;
- Rubber products and polymer manufacturing; and
- Polyethylene, polystyrene, and polyester resin manufacturing.[219]

In a number of cases, catalytic oxidation has been used to control CO and VOC emissions from natural gas-fired combustion turbines since oxidation catalysts are suitable for gas streams with negligible particulate loading. However, based on a review of the RBLC database and power plant air permits, catalytic oxidation is not a demonstrated technology for oil-fired boilers. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

Several factors render VOC catalytic oxidation not applicable for oil-fired boilers. First, the particulate loading of the flue gas stream could plug the oxidation catalyst. In addition, trace elements present in oil and the resulting combustion gases (e.g., sulfur in particular[220]) could foul the oxidation catalyst and reduce its effectiveness. Furthermore, SO_2 in the flue gas stream could be oxidized to form SO_3, which could react with the moisture in the flue gas to form sulfuric acid and create a corrosive environment. For these reasons, VOC catalytic oxidation is not an applicable technology for oil-fired boilers.

Additionally, catalytic oxidation is not an available technology for the auxiliary boiler. Typical commercially available package catalytic oxidizers can handle exhaust gas flow rates of up to 50,000 scfm,[221] while the auxiliary boiler will have an exhaust flow rate of approximately 70,000 scfm, 40% above the commercially available range for package units. Thus, VOC catalytic oxidation is not an available technology for the auxiliary boiler.

As discussed in this section, catalytic oxidation is not available or applicable. Therefore, catalytic oxidation is determined to be technically infeasible for the auxiliary boiler.

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[219] U.S. EPA, document no. EPA-452/F-03-018: *Air Pollution Control Technology Fact Sheet - Catalytic Incinerator*, p. 3.
[220] Ibid.
[221] Ibid.

External Thermal Oxidation (ETO)

ETO is generally utilized for controlling CO, VOC, or organic HAP emissions from high-concentration, non-combustion sources (e.g., surface coating operations and chemical plants). Based on a review of the RBLC database and power plant permits, regenerative ETO and recuperative ETO have not been demonstrated for use on an oil-fired boiler. Therefore, an assessment of the availability and applicability of this technology is conducted to determine if the technology is technically feasible.

ETO is not applicable for auxiliary boiler VOC control for the same reason as afterburners. Since the auxiliary boiler will be carefully tuned to maximize fuel combustion efficiency (i.e., subsequently minimizing VOC emissions) while minimizing NO_X formation, the process will result in essentially complete combustion. Therefore, additional ETO combustion would not be expected to provide any useful benefit (i.e., the auxiliary boiler serves as a thermal oxidizer where high combustion efficiency is a primary concern), and ETO is determined to be not applicable.

Additionally, the regenerative and recuperative ETO heat exchange systems would be vulnerable to the same sulfur concerns as discussed for VOC catalytic oxidation above. SO_2 in the flue gas stream could be oxidized to form SO_3, which could react with the moisture in the flue gas to form sulfuric acid and create a corrosive environment.

For the reasons discussed above, ETO is not applicable. Therefore, ETO is determined to be technically infeasible.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, combustion controls are the only remaining feasible control technology. Table 10.50 ranks the feasible VOC control technologies by effectiveness when applied to the Facility.

Table 10.50 - Ranking of VOC Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu)
Combustion Controls	0.003

Energy Impacts

Combustion controls are an integral part of the combustion process and are designed to maximize combustion efficiency while maintaining optimal VOC and NO_X emissions performance. Thus, combustion controls do not create any energy impacts.

Environmental Impacts

Since maximum fuel combustion efficiency (i.e., minimum VOC emission rate) occurs at the high end of the combustion temperature range, there is a potential for increased NO_X emissions due to thermal NO_X formation. Since NO_X formation is a concern, combustion controls are designed and operated to minimize VOC and NO_X formation while maximizing combustion efficiency. Thus, combustion controls do not create any significant environmental impacts.

Economic Impacts

Combustion controls are part of the standard design of modern oil-fired boilers and do not create any economic impacts.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of combustion controls are evaluated below.

Energy Impacts

There are no energy impacts that preclude the selection of combustion controls as VOC BACT.

Environmental Impacts

As discussed in Step 3, combustion controls are designed to minimize VOC emissions while maintaining an appropriate balance with NO_X formation. There are no environmental impacts that preclude the selection of combustion controls as VOC BACT.

Economic Impacts

There are no economic impacts that preclude the selection of combustion controls as VOC BACT.

Since there are no energy, environmental, or economic impacts that preclude the use of combustion controls, this technology is selected as VOC BACT for the auxiliary boiler.

Step 5 – Select BACT

Based on the analysis presented above, BACT for VOC emissions control is the application of combustion controls with an emission limit of 0.003 lb/MMBtu on a 3-hour average basis.

10.6.6 Sulfuric Acid (H_2SO_4)

SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. A small portion of the SO_2 may be oxidized to SO_3. The SO_3 can subsequently combine with water vapor to form H_2SO_4. The amount of H_2SO_4 formed depends on the amount of SO_3 and water vapor present and the temperature of the flue gas.

<u>Step 1 – Identify All Control Technologies</u>

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for control of H_2SO_4 emissions are pre-combustion technologies that have the potential to result in lower levels of H_2SO_4 emissions. Lower emitting processes/practices include the following:

<u>Fuel Selection</u>

Oil-fired boiler H_2SO_4 emissions are directly proportional to the sulfur content of the oil used. Therefore, the potential for H_2SO_4 formation can be reduced by firing oil with a low sulfur content. Modern low sulfur oils (e.g., ultra low sulfur distillate with sulfur content of 0.0015% by weight) will be available to minimize the amount of H_2SO_4 generated. Since this fuel will be available and results in virtually negligible H_2SO_4 emissions, the use of ultra low sulfur distillate oil is considered the baseline for the remainder of this analysis.

Add-On Controls

Due to the use of ultra low sulfur distillate fuel, the H_2SO_4 concentration in the auxiliary boiler exhaust will be extremely low (i.e., approximately 0.02 ppmv). Based on a review of the RBLC database, permits for other power plants, and discussions with vendors, no add-on H_2SO_4 controls have been installed on a boiler firing ultra low sulfur distillate fuel, and no add-on controls have been demonstrated as available for reducing emissions below ultra low sulfur distillate baseline emissions level. Thus, consistent with EPA guidance,[222] add-on controls are not considered in this analysis.

<u>Step 2 – Eliminate Technically Infeasible Options</u>

In this step, the potentially applicable H_2SO_4 control technologies identified in Step 1 are evaluated for technical feasibility. Fuel selection (i.e., the use of low sulfur fuels) is widely used to minimize emissions and is considered technically feasible.

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[222] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.73. The example illustrates that EPA does not expect analysis of add-on controls when the emission rate with a clean-burning fuel is on the same order as other sources controlled with stringent add-on controls.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Table 10.51 ranks the feasible H_2SO_4 control technologies by effectiveness for the auxiliary boiler.

Table 10.51 - Ranking of H_2SO_4 Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu)
Ultra Low Sulfur Distillate Fuel [(1)]	6.0×10^{-5}

Notes:
(1) Control effectiveness based on ultra low sulfur distillate fuel with a sulfur content of 15 ppm by weight or less.

Energy Impacts

Ultra low sulfur distillate fuel has a heating value of 19,200 Btu/lb and does not present any energy impacts.

Environmental Impacts

As with any liquid fuel, the ultra low sulfur distillate fuel is stored in a storage tank prior to use. WPEA will apply BACT to minimize emissions from the fuel storage tank.

Economic Impacts

Although ultra low sulfur distillate fuel may present a higher cost than lower-grade distillate fuels, economic impacts are not calculated since ultra low sulfur distillate fuel is considered the base case.

Step 4 – Evaluate Most Effective Controls and Document Results

Step 4 evaluates the energy, environmental and economic impacts of ultra low sulfur distillate fuel for minimizing H_2SO_4 emissions from the auxiliary boiler.

Energy Impacts

As discussed in Step 3, there are no energy impacts associated with ultra low sulfur distillate fuel.

Environmental Impacts

The environmental impacts associated with a fuel storage tank are minimal and do not preclude the use of ultra low sulfur distillate fuel as BACT.

Economic Impacts

While there may be a higher cost associated with the use of ultra low sulfur distillate fuel, this potential economic impact does not preclude the use of this fuel as BACT.

Since there are no energy, environmental, or economic impacts that preclude the use of ultra low sulfur distillate, this technology is selected as H_2SO_4 BACT for the auxiliary boiler.

Step 5 – Select BACT

Based on the above analysis, BACT for H_2SO_4 emissions is the use of ultra low sulfur distillate fuel (≤15 ppm sulfur) with an emission limit of 6.0×10^{-5} lb/MMBtu on a 3-hour average basis.

10.7 Non-Combustion Material Storage and Handling Systems

Non-combustion source PM emissions are created as a result of the breakdown of solid material into fines which have the potential to become airborne. This process is commonly referred to as dusting. Non-combustion particulate emissions are generated primarily as a result of the storage and handling of coal, ash and lime materials.

10.7.1 Non-Fugitive Material Handling Emissions

This section contains the BACT analysis for the non-fugitive material (e.g. coal, ash, lime) handling systems for the applicable regulatory pollutants identified in Table 10.2.

Non-fugitive emissions are those that pass through a stack, chimney, vent, or other functionally equivalent opening. By enclosing material handling operations, they are converted from a fugitive source into a point or area source. More stringent control measures may be available for emissions passing through functionally equivalent openings.

Enclosures are applied where reasonably practical throughout the Facility. The technical feasibility of an enclosure depends on a number of factors including the functionality, safety, and practicality of the enclosure for the specific application. For example, transfer point enclosures, usually used in conjunction with other control technologies such as water sprays or fabric filters, are a technically feasible particulate control technology for material transfer points where structural and operational considerations do not preclude their use.

The Facility includes the following enclosed material handling sources:

- S08 – Emergency Pile Reclaim
- S13 – Active Pile Reclaim
- S15 – Transfer Tower
- S17 – Tripper Deck
- S27 – Fly Ash Mixing Station
- S35 – Lime Railcar Unloading Station

<u>Step 1 – Identify All Control Technologies</u>

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes and practices for the control of PM/PM_{10} emissions are controls that lower the PM/PM_{10} generation rate. Potential lower emitting processes include the following:

<u>Water and/or Surfactant Sprays</u>

Water and/or surfactant sprays control the creation of PM/PM_{10} emissions by binding the smaller particles to the surface of the material, or by actively suppressing PM/PM_{10} emissions through direct contact between spray droplets and PM/PM_{10} suspended in the air.

Add-On Controls

Add-on controls remove PM/PM_{10} from the air. Potential add-on controls include the following:

Fabric Filter

A fabric filter removes particles from the air by drawing dust-laden gas through a bank of filter tubes suspended in a housing. A filter cake, composed of the removed particulate, builds up on the dirty side of the bag. Periodically, the cake is removed through physical mechanisms (e.g., blast of compressed air from the clean side of the bag, mechanical shaking of the bags, etc.) which causes the cake to fall. The dust is then collected in a hopper and removed. Alternatively, the spent filter bags may be periodically replaced.

Vent Filter

Vent filters are passive filtration devices. Typically, a vent filter would be located at the top of a storage bin and would control emissions while the bin was being filled. The filter cloth system would typically be equipped with a mechanism (e.g., pulsed air or mechanical rapping) to periodically remove the filter cake from the cloth and return it to the storage bin below.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable particulate control technologies identified in Step 1 are each evaluated for technical feasibility.

Water and/or Surfactant Sprays

Water and/or surfactant sprays are a technically feasible means of controlling PM/PM_{10} emissions during material handling operations, but only to the extent that the material conditioning (e.g. addition of water) does not adversely impact the material or the material handling process. Examples of technically infeasible applications of this methodology would include the use of sprays to lime that must remain dry.

Fabric Filter

Fabric filters are technically feasible PM/PM_{10} emissions control technology whenever the PM/PM_{10} source can be enclosed and funneled through a vent.

Vent Filter

Vent filters are technically infeasible due to the need to actively exchange the air inside the sources creating air flows in excess of vent filter capability.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. Table 10.52 ranks the feasible particulate control technologies by effectiveness when applied to the Facility. The control efficiencies listed are engineering estimates for each technology.

Table 10.52 – Ranking of Particulate Control Technologies by Effectiveness

Control Technology	Control Efficiency (%) (1)
Fabric Filter	≥99%
Water and/or Surfactant Sprays	≥80%

Notes:
(1) Based on engineering estimates for each technology.

Energy Impacts

This subsection lists the energy impacts of the feasible particulate control options. The energy impacts for the particulate control options are presented in Table 10.53.

Table 10.53 – Summary of Energy Impacts for Particulate Control Options

Control Option	Energy Impacts
Fabric Filter	Nominal pressure drop across the filter.
Water and/or Surfactant Sprays	No energy impacts expected.

Environmental Impacts

This subsection lists the environmental impacts of the feasible particulate control options. The environmental impacts of the potential control devices are listed in Table 10.54.

Table 10.54 – Summary of Environmental Impacts for Particulate Control Options

Control Option	Impact
Fabric Filter	Collected solids would have to be periodically removed and disposed of in accordance with applicable regulations. Alternatively, collected solids would be reused where possible. Filter bags would be replaced and disposed of as needed.
Water and/or Surfactant Sprays	Would require increased water use for sprays.

Economic Impacts

Since WPEA is not proposing to eliminate any control technology based on cost, the economic impacts ($/ton) are not presented here.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the control technologies are evaluated below, starting with the most effective control.

Fabric Filter

A case-by-case consideration of energy, environmental, and economic impacts for a fabric filter is presented below.

Energy Impacts

As discussed in Step 3, a fabric filter will present a nominal pressure drop across the filter. This energy requirement is not significant enough to preclude the use of a fabric filter.

Environmental Impacts

As shown in Step 3, there are no environmental impacts that would preclude the use of a fabric filter.

Economic Impacts

There are no economic impacts that preclude the use of a fabric filter as BACT.

Since this technology presents no significant energy, environmental, or economic impacts, WPEA selects a fabric filter as BACT for the non-fugitive material handling emission sources.

Step 5 – Select BACT

Table 10.55 indicates the selected BACT for each non-fugitive, non-combustion, material handling PM/PM_{10} emissions source at the Facility.

Table 10.55 – BACT for Non-Fugitive Material Handling PM/PM_{10} Emission Sources

Emission Source	BACT
Lime Railcar Unloading, Active Pile Reclaim	Partial Enclosure and fabric filter with outlet grain loading of 0.01 gr/dscf
Transfer Tower, Tripper Deck, Fly Ash Mixing Station, and Emergency Pile Reclaim	Enclosure and Fabric Filter with outlet grain loading of 0.01 gr/dscf

10.7.2 Non-Fugitive Material Storage Emissions

This section contains the BACT analysis for the non-fugitive material (e.g. ash, carbon, lime) storage systems for the applicable regulatory pollutants identified in Table 10.2.

Non-fugitive emissions are those passing through a stack, chimney, vent, or other functionally-equivalent opening. By enclosing a material storage operation, it is converted from a fugitive source into a point or area source. More stringent control measures may be available for emissions passing through functionally equivalent openings.

Enclosures are applied where reasonably practical throughout the Facility. The technical feasibility of each of the different types of enclosures depends on a number of factors including the functionality, safety, and practicality of the enclosure for the specific application. For example, material storage buildings and silos are technically feasible technologies for the control of PM/PM_{10} emissions from material handling operations, but only in applications where structural and operational considerations do not preclude their use.

Enclosed material storage sources at the Facility include the following:

- S26, S33, S37 – Fly Ash, Carbon, and Lime Silos

<u>**Step 1 – Identify All Control Technologies**</u>

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes and practices for the control of PM/PM_{10} emissions are controls that lower the PM/PM_{10} generation rate. Potential lower emitting processes include the following:

<u>Water and/or Surfactant Sprays</u>

Water and/or surfactant sprays control the creation of PM/PM_{10} emissions by binding the smaller particles to the surface of the material, or by actively suppressing PM/PM_{10} emissions through direct contact between spray droplets and PM/PM_{10} suspended in the air.

Add-On Controls

Add-on controls remove PM/PM_{10} from the air. Potential add-on controls include the following:

<u>Fabric Filter</u>

A fabric filter removes particles from the air by drawing dust-laden gas through a bank of filter tubes suspended in a housing. A filter cake, composed of the removed particulate, builds up on the dirty side of the bag. Periodically, the cake is removed through physical mechanisms (e.g., blast of compressed air from the clean side of the bag, mechanical shaking of the bags, etc.) which causes the cake to fall. The dust is then collected in a hopper and removed. Alternatively, the spent filter bags may be periodically replaced.

Vent Filter

Vent filters are passive filtration devices. Typically, a vent filter would be located at the top of a storage bin and would control emissions while the bin was being filled. The filter cloth system would typically be equipped with a mechanism (e.g., pulsed air or mechanical rapping) to periodically remove the filter cake from the cloth and return it to the storage bin below. Vent filters are considered standard equipment for silos handling fine solids. Therefore, vent filters are assumed as the base case in this analysis.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable particulate control technologies identified in Step 1 are each evaluated for technical feasibility.

Water and/or Surfactant Sprays

Water and/or surfactant sprays are a technically feasible means of controlling PM/PM_{10} emissions during material handling operations, but only to the extent that the material conditioning (e.g. addition of water) does not adversely impact the material or the material handling process. For each of the material storage sources at the Facility, water addition would adversely impact the material or material handling process. Thus, water and/or surfactant sprays are technically infeasible for the material storage operations.

Fabric Filter

Fabric filters are a technically feasible PM/PM_{10} emissions control technology for material storage silos.

Vent Filter

Vent filters are a technically feasible PM/PM_{10} emissions control technology for material storage silos.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. Table 10.56 ranks the feasible particulate control technologies by effectiveness when applied to the Facility. The control efficiencies listed are engineering estimates for each technology.

Table 10.56 – Ranking of Particulate Control Technologies by Effectiveness

Control Technology	Control Efficiency (gr/dscf) (1)
Fabric Filter	0.01
Vent Filter	0.02

Notes:
(1) Based on engineering estimates for each technology.

Energy Impacts

This subsection lists the energy impacts of the feasible particulate control options. The energy impacts for the particulate control options are presented in Table 10.57.

Table 10.57 – Summary of Energy Impacts for Particulate Control Options

Control Option	Energy Impacts
Fabric Filter	Pressure drop across the filter.
Vent Filter	No energy impacts expected since vent filters operate under naturally occurring positive pressure created by the addition of material to the enclosure.

Environmental Impacts

This subsection lists the environmental impacts of the feasible particulate control options. The environmental impacts of the potential control devices are listed in Table 10.58.

Table 10.58 – Summary of Environmental Impacts for Particulate Control Options

Control Option	Impact
Fabric Filter	Collected solids would have to be periodically removed and disposed of in accordance with applicable regulations. Alternatively, collected solids would be reused where possible. Filter bags would be replaced and disposed of as needed.
Vent Filter	Filters would be replaced and disposed of as needed.

Economic Impacts

This subsection lists the economic impacts of the feasible particulate control options. Version 7.5 of EPA's Air Compliance Advisor program was used to estimate costs of a fabric filter baghouse for each of the storage silos. These cost impacts are detailed in Table 10.59.

Table 10.59 - Economic Impacts for PM/PM_{10} Control Options

Parameter	Fly Ash Silo Baghouse	Carbon Silo Baghouse	Lime Silo Baghouse
Flow, scfm	6,972	3,486	6,972
Baseline Outlet Grain Loading, gr/dscf	0.02	0.02	0.02
Baseline PM_{10} emissions, tpy	5.23	2.62	5.23
Outlet Grain Loading, gr/dscf	0.01	0.01	0.01
Purchased equipment costs (1)	22,000	21,000	22,000
Total capital investment	48,000	46,000	48,000
Utilities	370	190	370
Total annual costs	15,000	14,000	15,000
Incremental costs	15,000	14,000	15,000
PM_{10} emissions, tpy	2.62	1.31	2.62
Incremental removal	2.61	1.31	2.61
Incremental cost, $/ton	5,747	10,687	5,747

Notes:

(1) Costs estimated using Version 7.5 of EPA's Air Compliance Advisor program.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the control technologies are evaluated below, starting with the most effective control.

Fabric Filter

A case-by-case consideration of energy, environmental, and economic impacts for a fabric filter is presented below.

Energy Impacts

As discussed in Step 3, a fabric filter would create a pressure drop across the filter. This pressure drop would represent a negative energy impact.

Environmental Impacts

As shown in Step 3, a fabric filter would produce a solid waste stream. This waste stream would represent a negative environmental impact.

Economic Impacts

As shown in Table 10.59, fabric filters would result in significant negative economic impacts. These economic impacts are significant enough to preclude the use of fabric filters as BACT.

Based on the combination of the negative energy, environmental, and significant economic impacts, fabric filters are not selected as BACT. Since fabric filters are not selected as BACT, the next most effective technology is evaluated.

Vent Filter

A case-by-case consideration of energy, environmental, and economic impacts for a vent filter is presented below.

Energy Impacts

As discussed in Step 3, vent filter is not expected to create any negative energy impacts since air flow is created by the addition of material to the silos.

Environmental Impacts

As shown in Step 3, there are no environmental impacts that would preclude the use of a vent filter.

Economic Impacts

Vent filters are considered the base case and do not create any negative economic impacts.

Since no energy, environmental, or economic impacts preclude their use, vent filters are selected as BACT for the material storage silos.

Step 5 – Select BACT

Based on the preceding analysis, particulate BACT for the material storage silos is enclosures combined with vent filters with an emission limit of 0.02 gr/dscf.

10.7.3 Fugitive Emissions

This section contains the BACT analysis for the fugitive material (e.g. coal, ash, lime) storage and handling systems and roadway travel for the applicable regulatory pollutants identified in Table 10.2. EPA defines fugitive emissions in the Title V regulations as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening" (see title 40 of the Code of Federal Regulations, sections 70.2 and 71.2).

Fugitive sources at the Facility include the following:

- S06 – Coal Railcar Unloading Station
- S10, S20, S23, S25, S28, S30 – Coal, Bottom Ash, and Fly Ash Transfer Points
- S07, S11, S12, S18, S32 – Coal Piles and On-Site Disposal Facility
- S22 – Bottom Ash Bunker
- S38, S39 – Unpaved and Paved Roadway Travel

In a June 9, 1980 memorandum from the EPA Director Division of Stationary Source Enforcement on the PSD Applicability, South Hospah Mine, Edward E. Reich listed haul road traffic and loading, dumping and storage of coal as fugitive emissions. In addition, in the Order Denying Review of PSD Appeal No. 92-1 for the Hawaiian Commercial & Sugar Company July 20, 1992, the boiler ash handling and disposal system was identified as a source of fugitive dust. Also, EPA's AP-42 Section 13.2, Introduction to Fugitive Dust Sources includes subchapters on Paved and Unpaved Roads, Aggregate Handling and Storage Piles and Industrial Wind Erosion. All of the sources listed above fall into the categories of coal or aggregate unloading, conveying, handling, storage or roadway travel.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes and practices for the control of PM/PM_{10} emissions are controls that lower the PM/PM_{10} generation rate. Potential lower emitting processes include the following:

Water Sprays

Water sprays control the creation of PM/PM_{10} emissions by binding the smaller particles to the surface of the material, or by actively suppressing PM/PM_{10} emissions through direct contact between spray droplets and PM/PM_{10} suspended in the air.

Material Conditioning

Material conditioning (i.e., maintaining a high moisture content in the material) is a method of controlling fugitive PM/PM_{10} emissions from material handling operations. The potential for dusting is minimized when fine particles in the material are bound with moisture.

Gravel/Chemical Suppressant

The application of gravel and/or chemical suppressants is a method of controlling fugitive PM/PM_{10} emissions from unpaved roadway travel. The presence of gravel and/or chemical suppressants prevents particles in the roadway from becoming airborne, thus minimizing emissions to the air.

Water Sprays/Sweeping

The application of water sprays and/or sweeping is a method of controlling fugitive PM/PM_{10} emissions from paved roadway travel. Water sprays bind the particulate with moisture, thus reducing the potential for dusting. Sweeping reduces the amount of particulate available for becoming airborne.

Partial Enclosures

Partial enclosures are an available particulate control option for material transfer points. Partial enclosures shield material transfer points from wind, thus minimizing potential particulate emissions generation.

Surface Sealants

Partial enclosures are an available particulate control option for material transfer points. Surface sealants are chemical treatments that create a protective layer on the surface of the material to bind and contain particulate, preventing it from becoming airborne.

Add-On Controls

Since these fugitive emissions could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening, no add-on controls are available.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable particulate control technologies identified in Step 1 are each evaluated for technical feasibility.

Water Sprays

Water sprays are a technically feasible means of controlling PM/PM_{10} emissions during material handling operations, but only to the extent that the water spray does not adversely impact the material or the material handling process.

Material Conditioning

Material conditioning is a technically feasible means of controlling PM/PM_{10} emissions during material handling operations, but only to the extent that the conditioning does not adversely impact the material or the material handling process.

Gravel and/or Chemical Suppressant

The use of gravel and/or chemical suppressants is a technically feasible control strategy for unpaved roadway travel PM/PM_{10} emissions control.

Water Sprays and/or Sweeping

The use of water sprays and/or sweeping is a technically feasible control strategy for paved roadway travel PM/PM_{10} emissions control.

Partial Enclosures

The technical feasibility of partial enclosures depends on a number of factors including the functionality, safety and practicality of the enclosure for the specific application. For example material transfer chutes are a technically feasible technology for the control of PM/PM_{10} emissions at material drop points.

Surface Sealants

Surface sealants are a technically feasible PM/PM_{10} emissions control technology only when applied to the surface of material that will not be frequently disturbed.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Table 10.60 ranks the feasible particulate control technologies by effectiveness when applied to the Facility. The control efficiencies listed are engineering estimates for each technology.

Table 10.60 – Ranking of Particulate Control Technologies by Effectiveness

Source Type	Control Technology	Control Efficiency (%) [1]
Unpaved Roadway Travel	Gravel and/or Chemical Suppressants	98% [2]
Coal Railcar Unloading Station	Partial Enclosure; Water sprays	≥85%
Active and Emergency Coal Piles and Active Areas of On-Site Disposal Facility	Water Sprays	85%
Bottom Ash and Fly Ash Transfer Points	Material Conditioning	85% [3]
Paved Roadway Travel	Water Sprays and/or Sweeping	85% [3]
Inactive Coal Pile and Inactive Areas of On-Site Disposal Facility	Surface Sealants (Crusting Agents)	80%
Coal Transfer Points and Bottom Ash Bunker	Partial Enclosure	50%

Notes:
(1) Based on engineering estimates for each technology as documented in Appendix 5.
(2) Per Malcolm Pirnie *Air Currents*, May 2000.
(3) Control efficiency assumed equal to water spray.

Energy Impacts

The available particulate control technologies are not expected to present any significant energy impacts.

Environmental Impacts

The water spray and surface sealant technologies will utilize a nominal amount of water to minimize particulate emissions. No other environmental impacts are expected.

Economic Impacts

Since WPEA is not proposing to eliminate any control technology based on cost, the economic impacts ($/ton) are not presented here.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the control technologies are evaluated below.

Energy Impacts

There are no energy impacts that would preclude the use of the fugitive emissions control technologies.

Environmental Impacts

As shown in Step 3, there are no environmental impacts that would preclude the use the fugitive emissions control technologies.

Economic Impacts

There are no economic impacts that would preclude the use of the fugitive emissions control technologies.

Step 5 – Select BACT

Table 10.61 indicates the selected BACT for each fugitive PM/PM_{10} emissions source at the Facility.

Table 10.61 – BACT Selection for Fugitive PM/PM_{10} Emission Sources

Source Type	BACT
Unpaved Roadway Travel	Gravel and/or Chemical Suppressants
Coal Railcar Unloading Station	Partial Enclosure; Water sprays
Active and Emergency Coal Piles and Active Areas of On-Site Disposal Facility	Water Sprays
Bottom Ash and Fly Ash Transfer Points	Material Conditioning
Paved Roadway Travel	Water Sprays and/or Sweeping
Inactive Coal Pile and Inactive Areas of On-Site Disposal Facility	Surface Sealants (Crusting Agents)
Coal Transfer Points and Bottom Ash Bunker	Partial Enclosure

10.8 Emergency Diesel Engines

This section contains the BACT analysis for the emergency diesel engines: the emergency diesel engine driven generator and the emergency diesel engine driven firewater pump. The generator and firewater pump are expected to operate no more than 500 and 150 hours per year, respectively.

10.8.1 Carbon Monoxide (CO)

Combustion is a thermal oxidation process in which carbon and hydrogen contained in a fuel combine with oxygen in the combustion zone to form CO_2 and H_2O. CO is generated during the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel. Properly designed and operated combustion units typically emit low levels of CO. High levels of CO emissions could result from poor design or sub-optimal firing conditions.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below. Per EPA's Draft NSR manual, control options incapable of meeting an applicable NSPS limit would not meet the definition of BACT and are not considered in the BACT analysis.[223]

Lower Emitting Processes/Practices

Lower emitting processes/practices are combustion control techniques that maximize the thermal oxidation of carbon to minimize the formation of CO. Lower emitting processes/practices include the following:

Combustion Controls

Optimization of the design, operation, and maintenance of the combustion system is the primary mechanism available for lowering CO emissions. This process is often referred to as combustion controls.

Add-On Controls

Add-on controls are devices that remove or destroy emissions in the exhaust after formation during combustion. The following add-on controls are potentially available.

Non-Selective Catalytic Reduction (NSCR)

NSCR is a catalytic reactor that simultaneously reduces CO, NO_X, and hydrocarbons. The catalytic reactor is placed in the exhaust stream of the engine and requires low oxygen levels and fuel-rich air-to-fuel ratios.

[223] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.12.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable control technologies identified in Step 1 are each evaluated for technical feasibility.

Combustion Controls

Combustion controls are a demonstrated technology and are considered technically feasible for the emergency diesel engines.

Non-Selective Catalytic Reduction (NSCR)

NSCR is deemed technically infeasible due to the small size and intermittent operation of the emergency diesel engines.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, combustion controls are the only remaining feasible control technology. Table 10.62 ranks the feasible CO control technologies by effectiveness when applied to the Facility.

Table 10.62 - Ranking of CO Control Technologies by Effectiveness

Emission Source	Control Technology	Control Effectiveness (lb/MMBtu) (1)
Emergency Diesel Generator	Combustion Controls	0.75
Emergency Firewater Pump	Combustion Controls	0.82

Notes:
(1) Equivalent to NSPS Subpart IIII emission limits for each engine.

Energy Impacts

Combustion controls are an integral part of the combustion process and are designed to maximize combustion efficiency while maintaining optimal emissions performance. Thus, combustion controls do not create any energy impacts.

Environmental Impacts

Combustion controls are designed to achieve an optimum balance between thermal efficiency-related emissions (e.g., CO and VOC) and temperature-related emissions (e.g., NO_X). By considering the optimum balance, combustion controls do not create any significant environmental impacts.

Economic Impacts

Combustion controls are part of the standard design of modern engines and do not create any economic impacts.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of combustion controls are evaluated below.

Energy Impacts

There are no energy impacts that preclude the selection of combustion controls as BACT.

Environmental Impacts

As discussed in Step 3, combustion controls are designed to minimize CO emissions while maintaining an appropriate balance with NO_X formation. There are no environmental impacts that preclude the selection of combustion controls as BACT.

Economic Impacts

There are no economic impacts that preclude the selection of combustion controls as BACT.

Step 5 – Select BACT

Based on the preceding analysis, BACT for CO emissions is the application of combustion controls with emission limits of 0.75 lb/MMBtu and 0.82 lb/MMBtu for the emergency diesel generator and firewater pump, respectively. Each of the limits is proposed on a 3-hour average basis.

The emission limits for the engines reflect the applicable NSPS Subpart IIII compression ignition (CI) engine CO emission limits promulgated on July 11, 2006. This finding is consistent with BACT decisions for other emergency diesel combustion sources in all recent permit reviews for support equipment at new coal-fired power plants.

10.8.2 Nitrogen Oxides (NO_X)

NO_X is the term used to collectively refer to NO and NO_2. NO_X is formed by the oxidation of nitrogen contained in the fuel (fuel NO_X), and when elemental nitrogen and oxygen in the combustion air combine within the high temperature environment of the combustion zone (thermal NO_X). Factors affecting the generation of NO_X include flame temperature, residence time, quantity of excess air, and the nitrogen content of the fuel.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below. Per EPA's Draft NSR manual, control options incapable of meeting an applicable NSPS limit would not meet the definition of BACT and are not considered in the BACT analysis.[224]

Lower Emitting Processes/Practices

Lower emitting processes/practices for NO_X reduction are the use of fuels with lower nitrogen content and combustion control technologies designed to limit the formation of NO_X by controlling the combustion temperature and the mixing of air and fuel in the combustion zone. These technologies are generally limited in the amount of reduction possible. The lower emitting processes/practices are described in more detail below.

Fuel Selection

Selecting a fuel oil with low nitrogen content would result in lower NO_X emissions though it must be noted that fuels are typically selected based on other criteria more critical to the operation of the engine such as heating value and sulfur content.

Combustion Controls

NO_X combustion controls for a diesel engine include injection timing retard, preignition chamber combustion, air-to-fuel ratio, or derating of the engine. The method used depends on the size and purpose for each type of diesel engine.

Add-On Controls

Add-on controls for NO_X reduction are post-combustion technologies that rely on chemical reactions within the control device to reduce the concentration of NO_X after the combustion process is complete. Add-on controls for NO_X include the following:

Selective Catalytic Reduction (SCR)

SCR is a post-combustion NO_X reduction technology in which ammonia is added to the flue gas upstream of a catalyst bed. The ammonia and NO_X react on the surface of the catalyst, forming N_2 and water. SCR reactions occur in a temperature range of

[224] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.12.

650 °F to 750 °F.[225] Typical catalyst material is titanium dioxide, tungsten trioxide, or vanadium pentoxide.

Non-Selective Catalytic Reduction (NSCR)

NSCR is a catalytic reactor that simultaneously reduces CO, NO_X, and hydrocarbons. The catalytic reactor is placed in the exhaust stream of the engine and requires low oxygen levels and fuel-rich air-to-fuel ratios.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable control technologies identified in Step 1 are each evaluated for technical feasibility.

Fuel Selection

While lower nitrogen fuel could presumably result in lower NO_X emissions, fuel oils are categorized by boiling point (e.g., heavy residual vs. light distillate) and sulfur content. Since a supply of low nitrogen fuel oil is not readily available, fuel selection is deemed technically infeasible. However, the facility will utilize ultra low sulfur distillate fuel, which typically contains less nitrogen content as a result of the hydroprocessing conducted during production to remove sulfur from the fuel.[226]

Combustion Controls

Combustion controls are a demonstrated technology and are considered technically feasible for the emergency diesel engines.

Selective Catalytic Reduction (SCR)

SCR is deemed technically infeasible due to the small size and intermittent operation of the emergency diesel engines.

Non-Selective Catalytic Reduction (NSCR)

NSCR is deemed technically infeasible due to the small size and intermittent operation of the emergency diesel engines.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

[225] Srivastava, et al., Nitrogen Oxides Emission Control Options for Coal-fired Electric Utility Boilers, *Journal of the Air & Waste Management Association,* Vol. 55, September 2005, p. 1374.
[226] U.S. EPA, 66 FR 35379, July 5, 2001.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, combustion controls are the only remaining feasible control technology. Table 10.63 ranks the feasible NO_X control technologies by effectiveness when applied to the Facility.

Table 10.63 - Ranking of NO_X Control Technologies by Effectiveness

Emission Source	Control Technology	Control Effectiveness (lb/MMBtu) (1)
Emergency Diesel Generator	Combustion Controls	1.37
Emergency Firewater Pump	Combustion Controls	0.94

Notes:
(1) Equivalent to NSPS Subpart IIII emission limits for each engine.

Energy Impacts

Combustion controls are an integral part of the combustion process and are designed to maximize combustion efficiency while maintaining optimal emissions performance. Thus, combustion controls do not create any energy impacts.

Environmental Impacts

Combustion controls are designed to achieve an optimum balance between thermal efficiency-related emissions (e.g., CO and VOC) and temperature-related emissions (e.g., NO_X). By considering the optimum balance, combustion controls do not create any significant environmental impacts.

Economic Impacts

Combustion controls are part of the standard design of modern engines and do not create any economic impacts.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of combustion controls are evaluated below.

Energy Impacts

There are no energy impacts that preclude the selection of combustion controls as BACT.

Environmental Impacts

As discussed in Step 3, combustion controls are designed to minimize efficiency-related emissions while maintaining an appropriate balance with NO_X formation. Thus, there are no environmental impacts that preclude the selection of combustion controls as BACT.

Economic Impacts

There are no economic impacts that preclude the selection of combustion controls as BACT.

Step 5 – Select BACT

Based on the analysis presented above, BACT for NO_X emissions is the application of combustion controls with emission limits of 1.37 lb/MMBtu and 0.94 lb/MMBtu for the emergency diesel generator and firewater pump, respectively. Each of the limits is proposed on a 3-hour average basis.

The emission limits for the engines reflect the applicable NSPS Subpart IIII compression ignition (CI) engine NO_X emission limits promulgated on July 11, 2006. This finding is consistent with BACT decisions for other emergency diesel combustion sources in all recent permit reviews for support equipment at new coal-fired power plants.

10.8.3 Sulfur Dioxide (SO_2)

SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. The SO_2 generally remains in a gaseous phase throughout the flue gas flow path.

<u>Step 1 – Identify All Control Technologies</u>

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for control of SO_2 emissions are pre-combustion technologies that have the potential to result in lower levels of SO_2 emissions. Lower emitting processes/practices include the following:

<u>Fuel Selection</u>

Oil-fired engine SO_2 emissions result from the oxidation of sulfur contained in the oil during the combustion process. Therefore, the potential for SO_2 formation can be reduced by firing oil with a low sulfur content. Modern low sulfur oils (e.g., ultra low sulfur distillate with sulfur content of 0.0015% by weight) will be available to minimize the amount of SO_2 formed during combustion. Since this fuel will be available and results in virtually negligible SO_2 emissions, the use of ultra low sulfur distillate oil is considered the baseline for the remainder of this analysis.

Add-On Controls

Due to the use of ultra low sulfur distillate fuel, SO_2 emissions and exhaust concentrations will be extremely low. Based on a review of EPA's AP-42 Section 3.3 Gasoline and Diesel Industrial Engines, EPA's AP-42 Section 3.4 Large Stationary Diesel and All Dual-Fuel Stationary Engines, the RBLC database, and recent permits or permit applications, no add-on controls are available to remove SO_2 below the uncontrolled levels corresponding to ultra low sulfur distillate combustion. Thus, consistent with EPA guidance,[227] add-on controls are not considered in this analysis.

<u>Step 2 – Eliminate Technically Infeasible Options</u>

In this step, the potentially applicable SO_2 control technologies identified in Step 1 are evaluated for technical feasibility. Fuel selection (i.e., the use of low sulfur fuels) is widely used to minimize SO_2 emissions and is considered technically feasible.

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[227] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.73. The example illustrates that EPA does not expect analysis of add-on controls when the emission rate with a clean-burning fuel is on the same order as other sources controlled with stringent add-on controls.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Table 10.64 ranks the feasible SO_2 control technologies by effectiveness for the emergency diesel engines.

Table 10.64 - Ranking of SO_2 Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu)
Ultra Low Sulfur Distillate Fuel (1)	1.6×10^{-3}

Notes:
(1) Control effectiveness based on ultra low sulfur distillate fuel with a sulfur content of 15 ppm by weight or less.

Energy Impacts

Ultra low sulfur distillate fuel has a heating value of 19,200 Btu/lb and does not present any energy impacts.

Environmental Impacts

As with any liquid fuel, the ultra low sulfur distillate fuel is stored in storage tanks prior to use. WPEA will apply BACT to minimize emissions from fuel storage.

Economic Impacts

Although ultra low sulfur distillate fuel may present a higher cost than lower-grade distillate fuels, economic impacts are not calculated since ultra low sulfur distillate fuel is considered the base case.

Step 4 – Evaluate Most Effective Controls and Document Results

Step 4 evaluates the energy, environmental and economic impacts of ultra low sulfur distillate fuel for minimizing SO_2 emissions from the emergency engines.

Energy Impacts

As discussed in Step 3, there are no energy impacts associated with ultra low sulfur distillate fuel.

Environmental Impacts

The environmental impacts associated with a fuel storage tank are minimal and do not preclude the use of ultra low sulfur distillate fuel as BACT.

Economic Impacts

While there may be a higher cost associated with the use of ultra low sulfur distillate fuel, this potential economic impact does not preclude the use of this fuel as BACT.

Since there are no energy, environmental, or economic impacts that preclude the use of ultra low sulfur distillate, this technology is selected as SO_2 BACT for the emergency diesel engines.

Step 5 – Select BACT

Based on the preceding analysis, BACT for SO_2 emissions is the use of ultra low sulfur (15 ppm sulfur) distillate fuel with an emission limit of 1.6×10^{-3} lb/MMBtu applicable to both of the engines. The limit is proposed on a 3-hour average basis.

10.8.4 Particulate Matter (PM / PM_{10})

Particulate matter (PM) is the general term for a mixture of solid particles and liquid droplets present in the emissions stream. PM emissions that are less than 10 microns in diameter are referred to as PM_{10}.

EPA identifies two types of smoke that may be emitted from diesel engines during stable operations (i.e., blue smoke and black smoke). Per EPA's AP-42 Section 3.3 (Gasoline and Diesel Industrial Engines), blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. The primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion mixtures that are oxygen deficient.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for control of PM/PM_{10} emissions are pre-combustion technologies that have the potential to result in lower levels of particulate formation. Lower emitting processes/practices include the following:

Combustion Controls

As discussed above, the primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion mixtures that are oxygen deficient. Combustion controls maximize combustion efficiency and minimize black smoke formation.

Proper Maintenance

As discussed above, blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. Per EPA's AP-42 Section 3.3 (Gasoline and Diesel Industrial Engines), proper maintenance is the most effective method of preventing blue smoke emissions from all types of IC engines.

Add-On Controls

Based on a review of EPA's AP-42 Section 3.3 Gasoline and Diesel Industrial Engines, EPA's AP-42 Section 3.4 Large Stationary Diesel and All Dual-Fuel Stationary Engines, the RBLC database, and other recent permits and permit applications, no available add-on controls for particulate were identified. Thus, no add-on controls are included in this analysis.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable particulate control technologies identified in Step 1 are each evaluated for technical feasibility.

Combustion Controls

Combustion controls are effective in minimizing particulate emissions and are considered technically feasible.

Proper Maintenance

Proper maintenance is effective in minimizing particulate emissions and is considered technically feasible.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Since combustion controls and proper maintenance can be used together to minimize particulate emissions, these two technologies are combined for the remainder of this analysis.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, the remaining technologies are ranked by control effectiveness. Table 10.65 ranks the feasible particulate control technologies by effectiveness when applied to the Facility.

Table 10.65 – Ranking of Particulate Control Technologies by Effectiveness

Emission Source	Control Technology	Control Effectiveness (lb/MMBtu) (1)
Emergency Diesel Generator	Combustion Controls + Proper Maintenance	0.04
Emergency Firewater Pump	Combustion Controls + Proper Maintenance	0.05

Notes:
(1) Equivalent to NSPS Subpart IIII emission limits for each engine.

Energy Impacts

Combustion controls and proper maintenance are not expected to create any energy impacts.

Environmental Impacts

Combustion controls and proper maintenance are not expected to create any environmental impacts.

Economic Impacts

Combustion controls and proper maintenance are not expected to create any economic impacts.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the control technologies are evaluated below.

Combustion Control + Proper Maintenance

A case-by-case consideration of energy, environmental, and economic impacts is presented below.

Energy Impacts

There are no energy impacts that would preclude combustion controls and proper maintenance as BACT.

Environmental Impacts

There are no environmental impacts that would preclude combustion controls and proper maintenance as BACT.

Economic Impacts

There are no economic impacts that would preclude combustion controls and proper maintenance as BACT.

Step 5 – Select BACT

Based on the preceding analysis, BACT for PM/PM_{10} emissions is combustion controls and proper maintenance with BACT limits of 0.04 lb/MMBtu and 0.05 lb/MMBtu for the emergency diesel generator and firewater pump, respectively.

The emission limits for the engines reflect the applicable NSPS Subpart IIII compression ignition (CI) engine particulate emission limits promulgated on July 11, 2006. This finding is consistent with BACT decisions for other emergency diesel combustion sources in all recent permit reviews for support equipment at new coal-fired power plants.

10.8.5 Volatile Organic Compounds (VOC)

Combustion is a thermal oxidation process in which carbon and hydrogen contained in a fuel combine with oxygen in the combustion zone to form CO_2 and H_2O. VOC is emitted from the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel. Properly designed and operated combustion systems typically emit low levels of VOC.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices are combustion control techniques that maximize the thermal oxidation of carbon to minimize the formation of VOC. Lower emitting processes/practices include the following:

Combustion Controls

Optimization of the design, operation, and maintenance of the combustion system is the primary mechanism available for lowering VOC emissions. This process is often referred to as combustion controls.

Add-On Controls

Add-on controls are devices that remove or destroy emissions in the exhaust after formation during combustion. The following add-on controls are potentially available.

Non-Selective Catalytic Reduction (NSCR)

NSCR is a catalytic reactor that simultaneously reduces CO, NO_X, and hydrocarbons (i.e., VOC). The catalytic reactor is placed in the exhaust stream of the engine and requires low oxygen levels and fuel-rich air-to-fuel ratios.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable control technologies identified in Step 1 are each evaluated for technical feasibility.

Combustion Controls

Combustion controls are a demonstrated technology and are considered technically feasible for the emergency diesel engines.

Non-Selective Catalytic Reduction (NSCR)

NSCR is deemed technically infeasible due to the small size and intermittent operation of the emergency diesel engines.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Following elimination of the technically infeasible control technologies in Step 2, combustion controls are the only remaining feasible control technology. Table 10.66 ranks the feasible VOC control technologies by effectiveness when applied to the Facility.

Table 10.66 - Ranking of VOC Control Technologies by Effectiveness

Emission Source	Control Technology	Control Effectiveness (lb/MMBtu)
Emergency Diesel Generator	Combustion Controls	0.10 [(1)]
Emergency Firewater Pump	Combustion Controls	0.35 [(2)]

Notes:
(1) Based on vendor data.
(2) Emission limit from AP-42 Table 3.3-1.

Energy Impacts

Combustion controls are an integral part of the combustion process and are designed to maximize combustion efficiency while maintaining optimal emissions performance. Thus, combustion controls do not create any energy impacts.

Environmental Impacts

Combustion controls are designed to achieve an optimum balance between thermal efficiency-related emissions (e.g., CO and VOC) and temperature-related emissions (e.g., NO_X). By considering the optimum balance, combustion controls do not create any significant environmental impacts.

Economic Impacts

Combustion controls are part of the standard design of modern engines and do not create any economic impacts.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of combustion controls are evaluated below.

Energy Impacts

There are no energy impacts that preclude the selection of combustion controls as BACT.

Environmental Impacts

As discussed in Step 3, combustion controls are designed to minimize VOC emissions while maintaining an appropriate balance with NO_X formation. There are no environmental impacts that preclude the selection of combustion controls as BACT.

Economic Impacts

There are no economic impacts that preclude the selection of combustion controls as BACT.

Step 5 – Select BACT

Based on the preceding analysis, BACT for VOC emissions is combustion controls with emission limits of 0.10 lb/MMBtu and 0.35 lb/MMBtu for the emergency diesel generator and firewater pump engine, respectively. Each of the limits is proposed on a 3-hour average basis.

10.8.6 Sulfuric Acid (H_2SO_4)

SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. A small portion of the SO_2 may be oxidized to SO_3. The SO_3 can subsequently combine with water vapor to form H_2SO_4. The amount of H_2SO_4 formed depends on the amount of SO_3 and water vapor present and the temperature of the flue gas.

Step 1 – Identify All Control Technologies

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for control of H_2SO_4 emissions are pre-combustion technologies that have the potential to result in lower levels of H_2SO_4 emissions. Lower emitting processes/practices include the following:

Fuel Selection

Oil-fired engine H_2SO_4 emissions are directly proportional to the sulfur content of the oil used. Therefore, the potential for H_2SO_4 formation can be reduced by firing oil with a low sulfur content. Modern low sulfur oils (e.g., ultra low sulfur distillate with sulfur content of 0.0015% by weight) will be available to minimize the amount of H_2SO_4 generated. Since this fuel will be available and results in virtually negligible H_2SO_4 emissions, the use of ultra low sulfur distillate oil is considered the baseline for the remainder of this analysis.

Add-On Controls

Due to the use of ultra low sulfur distillate fuel, H_2SO_4 emissions and exhaust concentrations will be extremely low. Based on a review of EPA's AP-42 Section 3.3 Gasoline and Diesel Industrial Engines, EPA's AP-42 Section 3.4 Large Stationary Diesel and All Dual-Fuel Stationary Engines, the RBLC database, and recent permits or permit applications, no add-on controls are available to remove H_2SO_4 below the uncontrolled levels corresponding to ultra low sulfur distillate combustion. Thus, consistent with EPA guidance,[228] add-on controls are not considered in this analysis.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable H_2SO_4 control technologies identified in Step 1 are evaluated for technical feasibility. Fuel selection (i.e., the use of low sulfur fuels) is widely used to minimize H_2SO_4 emissions and is considered technically feasible.

[228] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.73. The example illustrates that EPA does not expect analysis of add-on controls when the emission rate with a clean-burning fuel is on the same order as other sources controlled with stringent add-on controls.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Table 10.67 ranks the feasible H_2SO_4 control technologies by effectiveness for the emergency diesel engines.

Table 10.67 - Ranking of H_2SO_4 Control Technologies by Effectiveness

Control Technology	Control Effectiveness (lb/MMBtu)
Ultra Low Sulfur Distillate Fuel (1)	6.0×10^{-5}

Notes:

(1) Control effectiveness based on ultra low sulfur distillate fuel with a sulfur content of 15 ppm by weight or less.

Energy Impacts

Ultra low sulfur distillate fuel has a heating value of 19,200 Btu/lb and does not present any energy impacts.

Environmental Impacts

As with any liquid fuel, the ultra low sulfur distillate fuel is stored in storage tanks prior to use. WPEA will apply BACT to minimize emissions from fuel storage.

Economic Impacts

Although ultra low sulfur distillate fuel may present a higher cost than lower-grade distillate fuels, economic impacts are not calculated since ultra low sulfur distillate fuel is considered the base case.

Step 4 – Evaluate Most Effective Controls and Document Results

Step 4 evaluates the energy, environmental and economic impacts of ultra low sulfur distillate fuel for minimizing H_2SO_4 emissions from the emergency engines.

Energy Impacts

As discussed in Step 3, there are no energy impacts associated with ultra low sulfur distillate fuel.

Environmental Impacts

The environmental impacts associated with a fuel storage tank are minimal and do not preclude the use of ultra low sulfur distillate fuel as BACT.

Economic Impacts

While there may be a higher cost associated with the use of ultra low sulfur distillate fuel, this potential economic impact does not preclude the use of this fuel as BACT.

Since there are no energy, environmental, or economic impacts that preclude the use of ultra low sulfur distillate, this technology is selected as H_2SO_4 BACT for the emergency diesel engines.

Step 5 – Select BACT

Based on the above analysis, BACT for H_2SO_4 emissions is the use of ultra low sulfur distillate fuel (≤15 ppm sulfur) with an emission limit of 6×10^{-5} lb/MMBtu applicable to both of the engines. The limit is proposed on a 3-hour average basis.

10.9 Fuel Storage Tanks

This section contains the BACT analysis for the fuel storage tanks for the only applicable regulated pollutant identified in Table 10.2 (i.e., VOC).

The fuel storage tanks will emit VOC as a result of changes in the liquid level and the outside temperature/pressure. Emissions resulting from changes to the liquid level are known as working losses. During filling of the tank, the rising liquid level forces air saturated with VOC vapors to be expelled from the tank to maintain the tank pressure. During emptying of the tank, outside air replaces the liquid in the tank. As this air becomes saturated with VOC vapors, it expands and a portion of the air is expelled to maintain constant pressure in the tank. Changes to the outside temperature and pressure create a pressure differential between the atmosphere and the tank vapor space, forcing VOC saturated vapors to be expelled from the tank. These losses are known as breathing or standing losses.

Each of the tanks will be equipped with conservation vent valves. These include both pressure relieve valves (to keep fuel vapors in the tank up to a safe pressure) and vacuum relief valves (to allow outside air to enter the tank to avoid a significant vacuum). Such valves are needed to accommodate pressure variations occurring with changes in ambient temperature and fuel level changes associated with filling and dispensing.

<u>Step 1 – Identify All Control Technologies</u>

A listing of potential control technologies is provided below.

Lower Emitting Processes/Practices

Lower emitting processes/practices for control of VOC emissions are use of floating roof tanks.

<u>Floating Roof Tank with a Double Wiper Seal</u>

A floating roof design with a double seal would incorporate an aluminum internal floating roof inside the tank and would include a double wiper vapor mounted seal. A floating roof would minimize the saturated vapor volume between the liquid level and tank roof, resulting in lower VOC emissions.

Add-On Controls

Add-on controls identified for VOC emissions reduction remove or destroy vapor releases. Add-on controls include the following:

<u>Pipeaway System</u>

A fixed roof design with a pipeaway system would include a series of pipes and valves that would divert vapors discharged from the tank to the truck delivering the fuel, which would then return the vapors to its associated terminal where vapor recovery systems are often employed.

Vapor Recovery

A fixed roof design with vapor recovery would divert vapors from the tank to a refrigeration unit that would condense the vapors and return them to the tank in liquid form.

Thermal Oxidation

A fixed roof design with thermal oxidation would divert vapors from the tank through a blower and into a thermal oxidation unit that would burn the vapors.

Step 2 – Eliminate Technically Infeasible Options

In this step, the potentially applicable VOC control technologies identified in Step 1 are evaluated for technical feasibility.

Floating Roof Tank with a Double Wiper Seal

This technology has been installed on fuel storage tanks and is therefore considered technically feasible.

Pipeaway System

This technology has been installed on fuel storage tanks and is therefore considered technically feasible.

Vapor Recovery

This technology has been installed on fuel storage tanks and is therefore considered technically feasible.

Thermal Oxidation

This technology has been installed on fuel storage tanks and is therefore considered technically feasible.

Step 3 – Rank Remaining Control Technologies by Effectiveness

Step 3 of the top-down process includes a ranking of the control technologies by effectiveness and a listing of the energy, environmental, and economic impacts for each technology. The elements of the analysis are presented below.

Ranking by Control Effectiveness

Table 10.68 ranks the feasible VOC control technologies by effectiveness when applied to the Facility. Additionally, Table 10.68 shows the emission rate corresponding to each feasible control technology at each proposed tank.

Table 10.68 – Ranking of VOC Control Technologies by Effectiveness

Control Technology	Control Efficiency (1)	Emission Rate (tpy)				
		S46	S47	S48	S49	S50
Vapor Recovery	99%	5.8×10^{-4}	5.1×10^{-6}	1.1×10^{-5}	1.9×10^{-6}	2.7×10^{-3}
Thermal Oxidation	98%	1.2×10^{-3}	1.0×10^{-5}	2.2×10^{-5}	3.8×10^{-6}	5.4×10^{-3}
Floating Roof Tank	55%	0.026	2.3×10^{-4}	5.0×10^{-4}	8.6×10^{-5}	0.12
Pipeaway system	46%	0.031	2.7×10^{-4}	6.0×10^{-4}	1.0×10^{-4}	0.15
Baseline (Fixed Roof Tanks with Conservation Vent Valves)	Baseline	0.058	5.1×10^{-4}	1.1×10^{-3}	1.9×10^{-4}	0.27

Notes:
(1) Control efficiency values based on vendor information and technical publications.

Energy Impacts

This subsection presents the energy impacts of the feasible VOC control options. The energy impacts for the VOC control options are shown in Table 10.69.

Table 10.69 – Summary of Energy Impacts for VOC Control Options

Control Option	Energy Impacts
Vapor Recovery	Energy would be required to operate refrigeration system. Potentially significant energy impact.
Thermal Oxidation	Supplementary natural gas fuel would be required. Natural gas usage would constitute an energy impact.
Floating Roof Tank	No energy impacts expected.
Pipeaway system	No onsite energy impacts would be expected at WPEA Facility. Potential offsite energy impacts could result from vapor recovery operations at the petroleum terminal facility where the vapors would be returned for processing.
Fixed Roof Tanks with Conservation Vent Valves	No energy impacts expected.

Environmental Impacts

This subsection lists the environmental impacts of the feasible VOC control options. A summary of the environmental impacts is included in Table 10.70 below.

Table 10.70 – Summary of Environmental Impacts for VOC Control Options

Control Option	Environmental Impacts
Vapor Recovery	Refrigeration system would present potential environmental impacts associated with refrigerant storage and use.
Thermal Oxidation	Combustion in thermal oxidizer would create combustion pollutants, including NO_X.
Floating Roof Tank	No environmental impacts expected.
Pipeaway system	No onsite environmental impacts would be expected at WPEA Facility. Potential offsite environmental impacts could result from vapor recovery operations at the petroleum terminal facility where the vapors would be returned for processing.
Baseline (Fixed Roof Tanks with Conservation Vent Valves)	No environmental impacts expected.

Economic Impacts

The economic impacts associated with the feasible control technologies are summarized below in Table 10.71. Additional details of the analysis are presented in Table 10.72. To ensure a worst-case economic analysis, only the highest-emitting tank (i.e., S50, the 500-gallon gasoline tank) is considered because analysis of this tank results in the lowest cost per ton for each control technology (the cost per ton would be higher for the other lower-emitting tanks).

Table 10.71 – Summary of Economic Impacts for VOC Control Options

Control Option	Emissions (tpy)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Vapor Recovery	2.7×10^{-3}	$917,603	$339,852,963
Thermal Oxidation	5.4×10^{-3}	$83,019	$191,972
Floating Roof Tank	0.12	$173,000	$866,666
Pipeaway System	0.15	$12,250	$12,250
Baseline (Fixed Roof Tanks with Conservation Vent Valves)	0.27	Baseline	Baseline

Table 10.72 - Detailed Economic Impacts Analysis for VOC Control Options

Parameter	Fixed Roof Tanks with Conservation Vent Valves	Pipeaway System	Floating Roof Tank	Thermal Oxidation	Vapor Recovery
Baseline VOC emissions, tpy	0.27	0.27	0.27	0.27	0.27
Removal	--	46%	55%	98%	99%
Emission Rate, tpy	--	0.15	0.12	5.4×10^{-3}	2.7×10^{-3}
Direct capital costs					
Purchased Equipment (1)	$332,000	$7,000	$656,000	$107,000	$1,194,000
Direct Installation	$166,000	$4,000	$219,000	$54,000	$597,000
Total Capital Cost	$498,000	$11,000	$656,000	$161,000	$1,791,000
Annual costs					
Indirects	$10,000	$215	$13,000	$3,000	$36,000
Capital recovery	$70,000	$1,000	$77,000	$19,000	$210,000
Total annual costs	$80,000	$1,470	$106,000	$22,000	$245,000
Incremental costs	--	$1,470	$26,000	$22,000	$245,000
VOC emissions, tpy	0.27	0.15	0.12	5.4×10^{-3}	2.7×10^{-3}
Removal over baseline, tpy	--	0.12	0.15	0.265	0.267
Cost Effectiveness, $/ton	--	12,250	173,000	83,019	917,603
Incremental Cost, $/ton	--	12,250	866,666	191,972	339,852,963

Notes:
(1) Purchased equipment costs based on vendor estimates.

Step 4 – Evaluate Most Effective Controls and Document Results

The potential energy, environmental, and economic impacts of the control technologies are evaluated below, starting with the most effective control.

Vapor Recovery

A case-by-case consideration of energy, environmental, and economic impacts for vapor recovery is presented below.

Energy Impacts

As shown in Step 3, energy would be required to operate the refrigeration system in the vapor recovery process. This energy requirement represents a negative energy impact.

Environmental Impacts

As shown in Step 3, the refrigeration system would present potential environmental impacts associated with refrigerant storage and use. The potential issues surrounding the storage and use of refrigerant represent a potential negative environmental impact.

Economic Impacts

As shown in Step 3, the average cost of controlling VOC with vapor recovery would be $917,603 per ton. The incremental cost would be $339,852,963 per ton. These costs are extremely high and represent a significant negative economic impact.

Due to the energy, potential environmental, and significant economic impacts, vapor recovery is not selected as BACT. Since this option is not selected as BACT, the next most effective technology is evaluated.

Thermal Oxidation

A case-by-case consideration of energy, environmental, and economic impacts for thermal oxidation is presented below.

Energy Impacts

As shown in Step 3, a thermal oxidation system would require supplementary natural gas fuel. Considering the low removal (i.e., 0.27 tpy VOC removal for the highest emitting tank), energy use in the form of natural gas combustion represents a negative energy impact for thermal oxidation.

Environmental Impacts

As shown in Step 3, combustion in a thermal oxidizer would create combustion pollutants, including NO_X. Creating combustion pollutants in exchange for a slight decrease in VOC emissions (0.27 tpy VOC removal for the highest emitting tank) would be an unfavorable compromise. Thus, the combustion pollutants associated with thermal oxidation represent a negative environmental impact.

Economic Impacts

As shown in Step 3, the average cost of controlling VOC with thermal oxidation would be $83,019 per ton. The incremental cost would be $191,972 per ton. These costs are extremely high and represent a significant negative economic impact.

Due to the energy, environmental, and significant economic impacts, thermal oxidation is not selected as BACT. Since this option is not selected as BACT, the next most effective technology is evaluated.

Floating Roof Tank

A case-by-case consideration of energy, environmental, and economic impacts for a floating roof tank is presented below.

Energy Impacts

As shown in Step 3, there are no energy impacts that would preclude the use of a floating roof tank as BACT.

Environmental Impacts

As shown in Step 3, there are no environmental impacts that would preclude the use of a floating roof tank as BACT.

Economic Impacts

As shown in Step 3, the average cost of controlling VOC with a floating roof would be $173,000 per ton. The incremental cost would be $866,666 per ton. These costs are extremely high and represent a significant negative economic impact.

Due to the significant economic impacts, a floating roof tank is not selected as BACT. Since this option is not selected as BACT, the next most effective technology is evaluated.

Pipeaway System

A case-by-case consideration of energy, environmental, and economic impacts for a pipeaway system is presented below.

Energy Impacts

As shown in Step 3, no onsite energy impacts would be expected from a pipeaway system at the WPEA Facility. However, potential offsite energy impacts could result from vapor recovery operations at the petroleum terminal facility where the vapors would be returned for processing. These potential impacts represent a potential negative energy impact.

Environmental Impacts

As shown in Step 3, no onsite environmental impacts would be expected from a pipeaway system at the WPEA Facility. However, potential offsite environmental impacts could result from vapor recovery operations at the petroleum terminal facility where the vapors would be returned for processing. These potential impacts represent a potential negative environmental impact.

Economic Impacts

As shown in Step 3, the average cost of controlling VOC with a pipeaway system would be $12,250 per ton. These costs are extremely high and represent a significant negative economic impact.

Due to the potential energy, potential environmental, and significant economic impacts, a pipeaway system is not selected as BACT. Since this option is not selected as BACT, the next most effective technology is evaluated.

Fixed Roof Tanks with Conservation Vent Valves

Case-by-case considerations of energy, environmental, and economic impacts for fixed roof tanks with conservation vent valves are presented below.

Energy Impacts

As shown in Step 3, there are no energy impacts that would preclude the use of fixed roof tanks with conservation vent valves as BACT.

Environmental Impacts

As shown in Step 3, there are no environmental impacts that would preclude the use of fixed roof tanks with conservation vent valves as BACT.

Economic Impacts

As shown in Step 3, there are no economic impacts that would preclude the use of fixed roof tanks with conservation vent valves as BACT.

Since no energy, environmental, or economic impacts preclude their selection, WPEA selects fixed roof tanks with conservation vent valves as VOC BACT for the fuel storage tanks.

Step 5 – Select BACT

Based on the preceding analysis, WPEA selects fixed roof tanks with conservation vent valves as BACT for the fuel storage tanks. Proposed BACT limits for the fuel storage tanks are the annual emission rates listed in Section 5 of this application.

Table 10.73 – Most Stringent CO Emission Limits for PC Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Indeck Energy Services of Otsego	MI	0.10	Combustion Controls	7/7/06 RBLC	Never constructed, NO_X limit after add-on controls is 0.25 lb/MMBtu
Old Dominion Electric Coop., Clover	VA	0.10	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.3 lb/MMBtu
Santee Cooper, Cross 1	SC	0.10	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.39 lb/MMBtu
Thoroughbred Generating Station	KY	0.10	Combustion Controls	12/02 Permit (KY DEP website)	Recent permit
LG&E, Trimble County Generating Station	KY	0.10	Combustion Controls	1/4/06 Permit (KY DEP website)	Recent permit
Desert Rock Energy Center	NM	0.10	Combustion Controls	7/06 EPA Region 9 Permit	Recent permit
Keystone Cogeneration	NJ	0.11	Combustion Controls	7/7/06 RBLC	NO_X limit after add-on controls is 0.17 lb/MMBtu
Chambers Cogeneration	NJ	0.11	Combustion Controls	7/7/06 RBLC	NO_X limit after add-on controls is 0.17 lb/MMBtu
Longview Power	WV	0.11	Combustion Controls	3/04 Permit (WV DEP website)	Recent permit
Limestone Station	TX	0.11	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.50 lb/MMBtu
Prairie State Generating Station	IL	0.12	Combustion Controls	4/05 Permit (EPA reg. 5 website)	Recent permit
Deseret Generation & Transmission, Bonanza	UT	0.12	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.55 lb/MMBtu
Wisconsin Electric, Elm Road Generating Station	WI	0.12	Combustion Controls	1/04 Permit	Recent permit
Comanche	CO	0.13	Combustion Controls	7/05 Permit	Recent permit
Associated Electric Cooperative, Inc.	MO	0.13	Combustion Controls	1/06 Application	Recent application

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Big Cajun II Power Plant	LA	0.135	Combustion Controls	7/7/06 RBLC	Annual average emission limit
Longleaf Energy Station	GA	0.15	Combustion Controls	11/04 application	Recent application
Sunflower Electric Coop – Holcomb	KS	0.15	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Duke Power – Cliffside	NC	0.15	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Palatka Generating Station (Seminole)	FL	0.15	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Sandy Creek Energy Station	TX	0.15	Combustion Controls	3/05 Draft Permit	Recent draft permit
Newmont Mining, TS Power Plant	NV	0.15	Combustion Controls	5/05 Permit	Recent permit
Two Elk Generation Partners	WY	0.15	Combustion Controls	7/7/06 RBLC	Recent permit
Black Hills Power, Wygen Unit 1	WY	0.15	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.22 lb/MMBtu
Black Hills Power, Neil Simpson	WY	0.15	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.23 lb/MMBtu
Sand Sage Power, Holcomb Unit 2	KS	0.15	Combustion Controls	1/02 Permit	Recent permit
Tucson Electric, Springerville Units 3 & 4	AZ	0.15	Combustion Controls	2/02 Permit	Recent permit
Dynegy, Baldwin Expansion	IL	0.15	Combustion Controls	4/02 Application	Recent application
Black Hills Power, Wygen Unit 2	WY	0.15	Combustion Controls	9/02 Permit	Recent permit
Bull Mountain Development, Roundup	MT	0.15	Combustion Controls	1/03 Permit	Recent permit
Mustang Generating Station	NM	0.15	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
City Public Service, Spruce Unit 2	TX	0.15	Combustion Controls	1/06 Permit	Recent permit

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Municipal Energy Agency of Nebraska (Whelan Energy)	NE	0.15	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Rocky Mtn Power, Hardin	MT	0.15	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Weston 4	WI	0.15	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Intermountain Power, Unit 3	UT	0.15	Combustion Controls	4/04 Permit	Recent permit
MidAmerican Energy, Council Bluffs	IA	0.154	Combustion Controls	4/03 Permit (IDNR website)	Recent permit
Otter Tail Power Company	SD	0.15	Combustion Controls	4/06 Draft Permit	Recent draft permit
Plum Point Energy Station	AR	0.16	Combustion Controls	7/7/06 RBLC	Recent permit
Kansas City Power & Light, Iatan Generating Station	MO	0.16	Combustion Controls	1/06 Permit	Recent permit
Omaha Public Power District	NE	0.16	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Kansas City Power & Light, Hawthorn 5a	MO	0.16	Combustion Controls	8/99 Permit	

Table 10.74 – Most Stringent NO_X Emission Limits for PC Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
City Public Service, Spruce Unit 2	TX	0.05 (1) 0.07	LNB +OFA + SCR	1/06 Permit	Recent permit
Sandy Creek Energy Station	TX	0.05 (1) 0.07	LNB + OFA + SCR	3/05 Draft Permit	Recent draft permit
Desert Rock Energy Center	NM	0.060 (3)	LNB + SCR	7/06 EPA Region 9 Permit	Recent permit
Weston 4	WI	0.06 (2) 0.07	LNB + OFA + SCR	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Newmont Mining	NV	0.067 (3)	LNB + OFA + SCR	5/05 Permit	Recent permit
MidAmerican Energy, Council Bluffs	IA	0.07	LNB +OFA + SCR	4/03 Permit (IDNR website)	Recent permit
Big Cajun II Power Plant	LA	0.07	LNB + SCR	8/05 Permit	Recent permit
Bull Mountain Development, Roundup Power	MT	0.07 (3) 0.10 (4)	LNB + OFA + SCR	1/03 Permit	Recent permit
Black Hills Power, Wygen Unit 2	WY	0.07	LNB + OFA + SCR	9/02 Permit	Recent permit
Wisconsin Energy, Elm Road Generating Station	WI	0.07	LNB + OFA + SCR	1/04 Permit	Recent permit
Intermountain Power, Unit 3	UT	0.07	LNB + SCR	4/04 Permit	Recent permit
Longleaf Energy Station	GA	0.07	LNB + OFA + SCR	11/04 Application	Recent application
Sunflower Electric Coop – Holcomb	KS	0.07	SCR	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Omaha Public Power District	NE	0.07 (5)	LNB + SCR	3/06 EPA Ntl Coal Database Sheet	Recent permit
Associated Electric Cooperative, Inc.	MO	0.08	SCR	1/06 Application	Recent application

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Kansas City Power & Light, Iatan Generating Station	MO	0.08	LNB + SCR	1/06 Permit	Recent permit
Duke Power – Cliffside	NC	0.08	LNB + SCR	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Santee Cooper Cross Generating Station, Unit 3&4	SC	0.08 (6)	LNB+SCR	02/04 Permit	Limit set in order to net out of PSD review with Cross Units 1 & 2.
Sand Sage Power, Holcomb Unit 2	KS	0.08 (5) (7)	LNB + OFA + SCR	1/02 Permit	Recent permit
Great Plains Power, Weston Bend	MO	0.08 (8)	LNB + OFA + SCR	11/01 Application	Recent application
Great Plains Power, Atchison Station	KS	0.08 (8)	LNB + OFA + SCR	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Dynegy, Baldwin Expansion	IL	0.08 (8)	LNB + OFA + SCR	4/02 Application	Recent application
Kansas City Power & Light, Hawthorn Unit 5a	MO	0.08 (9)	LNB + OFA + SCR	8/99 Permit	Operating, Over 2 years to achieve 0.08 lb/MMBtu
City Utilities of Springfield, Southwest Power Station	MO	0.08 (8)	SCR	12/04 Permit	Recent permit
Prairie State Generating Station	IL	0.08	LNB + OFA + SCR	4/05 Permit	Recent permit
Longview Power	WV	0.08 (3)	LNB + SCR	3/04 Permit (WV DEP website)	Recent permit
Thoroughbred Generating Station	KY	0.08	LNB + OFA + SCR	12/02 Permit (KY DEP website)	Recent permit
Comanche	CO	0.08	LNB + OFA + SCR	7/05 Permit	Recent permit
Municipal Energy Agency of Nebraska (Whelan Energy Center)	NE	0.08 (5)	SCR	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Plum Point Energy Station	AR	0.09 (3)	LNB + OFA + SCR	8/03 Permit	Recent permit

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Two Elk Generation Partners	WY	0.09	LNB + OFA + SCR	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit

Notes:

All limits are 30-day rolling average unless otherwise noted.

(1) 12-month rolling average – draft permit includes 12-month optimization study for SCR operation.
(2) Annual average
(3) 24-hour average
(4) 1-hour average
(5) Permit includes 18-month evaluation period for SCR operation. Emission limit is 0.12 lb/MMBtu during this period.
(6) 365-day rolling average
(7) Permit includes 36-month evaluation period for SCR operation. Emission limit is 0.15 lb/MMBtu during this period.
(8) Permit application requests a 36-month evaluation period for SCR operation
(9) Permit includes 36-month evaluation period for SCR operation. Emission limit is 0.12 lb/MMBtu during this period.

Table 10.75 – Most Stringent SO_2 Emission Limits for PC Boilers Utilizing Low Sulfur Western or PRB Coal

Facility	State	Emissions Limit (lb/MMBtu)	Control Efficiency (%)	Control Technology	Project Size (MW)	Permit or Application Date	Source	Notes
Deseret Generation & Transmission, Moonlake	UT	0.055	94	Wet scrubber		1980	7/7/06 RBLC	Never constructed. Permit expired.
City Public Service, Spruce Unit 2	TX	0.06 (1) 0.10 (2)	95	Wet scrubber	750	2005	1/06 Permit	Recent permit; Addition to existing site
Desert Rock	Navajo (NM)	0.06	97	Wet scrubber	2 x 750	2004	5/04 Permit application	Will utilize unproven proprietary sorbent injection process/chemical.
Arizona Public Service, Cholla Unit 5	AZ	0.072	94	Wet scrubber		1978	7/7/06 RBLC	Never constructed
Newmont Mining	NV	0.09 for S>0.45 0.065 for S<0.45 (3)	92.3	Dry scrubber	200	2003	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Intermountain Power Project, Unit 3	UT	0.09 (2) 0.10 (3)		Wet scrubber	950	2002	10/04 Permit	Recent permit; Addition to existing site
Kansas City Power & Light, Iatan Generating Station	MO	0.09 (2)		Wet scrubber	930	2006	1/06 Permit	Recent permit
Weston 4	WI	0.1 (2)	92	Dry Scrubber	500	2004	7/7/06 RBLC	Recent permit
Big Cajun II Power Plant	LA	0.10 (6)	90% for dry; not less than 90% for wet	Dry scrubber or wet scrubber	675	2005	8/05 Permit, 4/12/06 correspondence with permit engineer	Recent permit; Addition to existing site
Associated Electric Cooperative, Inc.	MO	0.10 (2)		Dry scrubber		2006	1/06 Permit application	Recent application

Facility	State	Emissions Limit (lb/MMBtu)	Control Efficiency (%)	Control Technology	Project Size (MW)	Permit or Application Date	Source	Notes
Nevada Power Company	NV	0.10 (2)	95	Wet scrubber		1981	7/7/06 RBLC	Never constructed
Comanche	CO	0.10 (2)		Dry scrubber	750	2005	7/05 Permit	Recent permit
Sandy Creek Energy Station	TX	0.10 (1) 0.12 (2)	92.7	Dry scrubber	800	2005	3/05 Draft Permit	Recent draft permit
Deseret Generation & Transmission, Bonanza	UT	0.10 (4) 0.15 (2)	90	Wet scrubber	485	1998/1986	7/7/06 RBLC	Per the RBLC database, the permit is 1998, however the plant became operational in 1986.
Black Hills Power, Wygen Unit 2	WY	0.10 (2) 0.15 (5)	70 minimum (30-day rolling avg.)	Dry scrubber	500	2002	9/02 Permit	Recent permit
Omaha Public Power District	NE	0.095 (2) 0.48 (5)		Dry scrubber	650	2004	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
City Utilities of Springfield, Southwest Power Station	MO	0.095 (2)		Dry scrubber	2 x 275	2004	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Sunflower Electric Coop – Holcomb	KS	0.10 (2)		Dry scrubber	3 x 660	2006	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
PacifiCorp, Hunter Unit 4	UT	0.10	90	Wet scrubber	575	1980/2004	3/06 EPA Ntl Coal Database Spreadsheet	Never constructed; resubmittal of application; Add'n to existing site.
MidAmerican Energy, Council Bluffs	IA	0.1		Dry scrubber	750	2003	4/03 Permit (IDNR website)	Recent permit

Facility	State	Emissions Limit (lb/MMBtu)	Control Efficiency (%)	Control Technology	Project Size (MW)	Permit or Application Date	Source	Notes
LG&E Trimble County Generating Station	KY	0.107		Wet Scrubber	750	2006	1/4/06 Permit (KY DEP website)	Recent permit
Rocky Mtn Power, Hardin	MT	0.11		Dry scrubber	116	2004	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit modification
Mustang Generating Station	NM	0.11		Dry scrubber	300	2002	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Bull Mountain Development, Roundup Power	MT	0.12 (3) 0.15 (6)		Dry scrubber	2 x 350	2002	1/03 Permit	Recent permit
Sand Sage Power, Holcomb Unit 2	KS	0.12 (2)	92.7 (est.)	Dry scrubber	600	2001	1/02 Permit	Recent permit
Great Plains Power, Weston Bend	MO	0.12 (2)	>90	Dry scrubber	820	2001	11/01 Application	Recent application
Great Plains Power, Atchison Station	KS	0.12 (2)	>90	Dry scrubber	820	2003	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Municipal Energy Agency of Nebraska (Whelan Energy Center)	NE	0.12 (2)		Dry scrubber	200	2004	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Kansas City Power & Light, Hawthorn Unit 5a	MO	0.12 (2)	92.5 (est.)	Dry scrubber	550	1999	8/99 Permit	
Longleaf Energy Station	GA	0.12 (2)		Dry scrubber	2 x 600	2004	11/04 Application	Recent application
Platte River Power, Rawhide	CO	0.13	80	Dry scrubber	250	1980	7/7/06 RBLC	
Otter Tail Power Company	SD	0.14	95	Wet Scrubber	600	2006	4/06 Draft Permit	Recent draft permit
Intermountain Power Project	UT	0.15 (2)	90	Wet scrubber	950	1983	7/7/06 RBLC	
Plum Point Energy Station	AR	0.16 (5)		Dry scrubber	800	2003	8/03 Permit	Recent permit

Facility	State	Emissions Limit (lb/MMBtu)	Control Efficiency (%)	Control Technology	Project Size (MW)	Permit or Application Date	Source	Notes
Two Elk Generation Partners	WY	0.17 (2) 0.20 (7)	91	Dry scrubber	500	1998	7/7/06 RBLC	
Tucson Electric Power, Springerville Units 3 & 4	AZ	Netted out		Dry scrubber	2 x 400	2002	4/02 Permit	Recent permit

Notes:

(1) Annual average
(2) 30-day rolling average
(3) 24-hour average
(4) 12-month rolling average
(5) 3-hour average
(6) 1-hour average
(7) 2-hour average

Table 10.76 - Most Stringent PM_{10} Emissions Limits for PC Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Desert Rock Energy Center	NM	0.10 (filterable) 0.20 (total)	Fabric Filter	7/06 EPA Region 9 Permit	Limits are on a 24-hr averaging period.
Newmont Mining	NV	0.012 (filterable) 0.038 (total)	Fabric Filter	11/04 Draft Permit	Recent draft permit. 0.012 lb/MMBtu limit is on 24-hr averaging period.
Black Hills Power, Wygen Unit 2	WY	0.012	Fabric Filter	9/02 Permit	Recent permit
Rocky Mtn Power, Hardin	MT	0.012	Fabric Filter	12/04 Permit	Recent permit modification
Otter Tail Power Company	SD	0.012	Fabric Filter	4/06 Draft Permit	Recent draft permit
Sunflower Electric Coop – Holcomb	KS	0.012 (filterable) 0.035 (total)	Fabric Filter	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Kansas City Power & Light, Iatan Generating Station	MO	0.014 (filterable) 0.0236 (total)	Fabric Filter	1/06 Permit	Recent permit
Longleaf Energy Station	GA	0.015 (filterable) 0.033 (total)	Fabric Filter	11/04 Application	Recent application
Comanche	CO	0.012 (filterable) 0.020 (total)	Fabric Filter	7/05 Permit	Recent permit
Sandy Creek Energy Station	TX	0.015 (filterable) 0.04 (total)	Fabric Filter	3/05 Draft Permit	Recent draft permit
Intermountain Power Project Unit 3	UT	0.015	Fabric Filter	4/04 Draft Permit	Recent draft permit
Bull Mountain Development, Roundup Power	MT	0.015	Fabric Filter	1/03 Permit	Recent permit
Mon Valley Energy Limited Partnership	PA	0.015	Fabric Filter	7/7/06 RBLC	Never constructed
Tucson Electric, Springerville Units 3 & 4	AZ	0.015	Fabric Filter	2/02 Permit	Recent permit
PacifiCorp, Hunter Unit 4	UT	0.015	Fabric Filter	3/06 EPA Ntl Coal Database Spreadsheet	Recent application

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Santee Cooper Cross Generating Station, Unit 3&4	SC	0.015 (filterable) 0.018 (total)	Fabric Filter	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Duke Power – Cliffside	NC	0.015	ESP + WESP	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Palatka Generating Station (Seminole)	FL	0.015	ESP + WESP	3/06 EPA Ntl Coal Database Spreadsheet	Recent Application
Big Cajun II Power Plant	LA	0.015	ESP + Fabric Filter	8/05 Permit	Recent permit
Associated Electric Cooperative, Inc.	MO	0.0163	Fabric Filter	1/06 Application	Recent application
Plum Point Energy Station	AR	0.018	Fabric Filter	8/03 Permit	Recent permit
Dynegy, Baldwin Expansion	IL	0.018	Fabric Filter	4/02 Application	
Prairie State Generating Station	IL	0.018	ESP	2/04 Permit (EPA reg. 5 website)	Recent permit
Thoroughbred Generating Station	KY	0.018	ESP	12/02 Permit (KY DEP website)	Recent permit
Old Dominion Electric Coop., Clover	VA	0.018	Fabric Filter	7/7/06 RBLC	
Great Plains Power, Weston Bend	MO	0.018	Fabric Filter	11/01 Application	Recent application
Sand Sage Power, Holcomb Unit 2	KS	0.018	Fabric Filter	1/02 Permit	Recent permit
SEI, Birchwood Power Facility	VA	0.018	Fabric Filter	7/7/06 RBLC	
Kansas City Power & Light, Hawthorn Unit 5a	MO	0.018	Fabric Filter	8/99 Permit	
South Carolina Electric & Gas, Units 1, 2, &3	SC	0.018	Fabric Filter	7/7/06 RBLC	
Keystone Cogeneration	NJ	0.018	Fabric Filter	7/7/06 RBLC	

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Wisconsin Electric, Elm Road Generating Station	WI	0.018	Fabric Filter	1/02 Application	Recent application
Weston 4	WI	0.018	Fabric Filter	7/7/06 RBLC	Recent permit
Omaha Public Power District	NE	0.018	Fabric Filter	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
LG&E Trimble County Generating Station	KY	0.018	Fabric Filter	1/4/06 Permit (KY DEP website)	Recent permit
Longview Power	WV	0.018 (6-hr rolling)	Fabric Filter	3/04 Permit (WV DEP website)	Recent permit
Weston 4	WI	0.02	Fabric Filter	7/7/06 RBLC	Recent permit
City Public Service, Spruce Unit 2	TX	0.022 (total – annual avg)	Fabric Filter	1/06 Permit	Recent permit
MidAmerican Energy, Council Bluffs	IA	0.025 (total)	Fabric Filter	4/03 Permit (IDNR website)	Recent permit

Table 10.77 - Most Stringent Opacity Emissions Limits for PC Boilers

Facility	State	Emissions Limit	Control Technology	Source	Notes
MidAmerican Energy, Council Bluffs	IA	5%	Fabric Filter	4/03 Permit (IDNR website)	Recent permit
Plum Point Energy Station	AR	10%	Fabric Filter	8/03 Permit	Recent permit
Sandy Creek Energy Station	TX	10%	Fabric Filter	3/05 Draft permit	Recent draft permit
Longleaf Energy Station	GA	10%	Fabric Filter	11/04 Application	Recent application
Mon Valley Energy Limited Partnership	PA	10%	Fabric Filter	7/7/06 RBLC	Never constructed
Reliant Energy, W A Parish Unit 8	TX	10%		7/7/06 RBLC	Draft permit
Intermountain Power Project Unit 3	UT	10%	Fabric Filter	4/04 Draft permit	Recent draft permit
Comanche	CO	10%	Fabric Filter	7/7/06 RBLC	Recent permit
City Public Service, Spruce Unit 2	TX	10%	Fabric Filter	1/06 Permit	Recent permit
Desert Rock Energy Center	NM	10%	Fabric Filter	7/06 EPA Region 9 Permit	Recent permit
LG&E Trimble County Generating Station	KY	20%	Fabric Filter	1/4/06 Permit (KY DEP website)	Recent permit
Kansas City Power & Light, Iatan Generating Station	MO	20%	Fabric Filter	1/06 Permit	Recent permit
Kansas City Power & Light, Hawthorn 5a	MO	20%	Fabric Filter	8/99 Permit	Recent permit
Thoroughbred Generating Station	KY	20%	ESP	12/02 Permit (KY DEP website)	Recent permit
Black Hills Power, Wygen Unit 1	WY	20%	Fabric Filter	7/7/06 RBLC	

Facility	State	Emissions Limit	Control Technology	Source	Notes
Deseret Generation & Transmission, Bonanza	UT	20%		7/7/06 RBLC	
Two Elk Generation Partners	WY	20%		1st Q, 2003 Call with WY DEQ permit engr.	Recent permit
Bull Mountain Development, Roundup Power	MT	20%	Fabric Filter	1/03 Permit	Recent permit
Otter Tail Power Company	SD	20%	Fabric Filter	4/06 Draft Permit	Recent draft permit
Tucson Electric, Springerville Units 3 & 4	AZ	20%	Fabric Filter	2/02 Permit	Recent permit

Table 10.78 – Most Stringent VOC Emissions Limits for PC Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Houston Lighting & Power	TX	0.001	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.6 lb/MMBtu
Santee Cooper Cross Generating Station, Unit 3&4	SC	0.0024	Combustion Controls	02/04 Permit	Review includes PSD BACT and LAER
City Public Service, Spruce Unit 2	TX	0.0025 (annual avg.)	Combustion Controls	1/06 Permit	Recent permit
Intermountain Power Project Unit 3	UT	0.0027	Combustion Controls	4/04 Draft permit	Recent draft permit
Mecklenburg Cogeneration L.P.	VA	0.0027	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.33 lb/MMBtu
Reliant Energy, W A Parish Unit 8	TX	0.0030	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.43 lb/MMBtu
Bull Mountain Development, Roundup Power	MT	0.0030	Combustion Controls	1/03 Permit	Recent permit
Reliant Energy, W A Parish Unit 7	TX	0.0030	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.32 lb/MMBtu
Desert Rock Energy Center	NM	0.0030	Combustion Controls	7/06 EPA Region 9 Permit	Limit is on a 24-hr averaging period.
LG&E, Trimble County Generating Station	KY	0.0032	Combustion Controls	1/4/06 Permit (KY DEP website)	Recent permit
Reliant Energy, W A Parish Units 5 & 6	TX	0.0031	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.38 lb/MMBtu
Omaha Public Power District	NE	0.0034	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Sunflower Electric Coop – Holcomb	KS	0.0035	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Tucson Electric, Springerville Units 3 & 4	AZ	0.0035	Combustion Controls	2/02 Permit	Recent permit – Permit limit is for ≤ 0.06 lb/T. lb/MMBtu estimate is based on 0.06 lb/T.

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Sand Sage Power, Holcomb Unit 2	KS	0.0035	Combustion Controls	8/02 Permit	Recent permit
Comanche	CO	0.0035	Combustion Controls	7/7/06 RBLC	Recent permit
Deseret Generation & Transmission, Bonanza	UT	0.0035	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.55 lb/MMBtu
MidAmerican Energy, Council Bluffs	IA	0.0036	Combustion Controls	4/03 Permit (IDNR website)	Recent permit
Keystone Cogeneration	NJ	0.0036	Combustion Controls	7/7/06 RBLC	NO_X limit after add-on controls is 0.17 lb/MMBtu
Chambers Cogeneration	NJ	0.0036	Combustion Controls	7/7/06 RBLC	NO_X limit after add-on controls is 0.17 lb/MMBtu
Kansas City Power & Light, Iatan Generating Station	MO	0.0036	Combustion Controls	1/06 Permit	Recent permit
Kansas City Power & Light, Hawthorn Unit 5a	MO	0.0036	Combustion Controls	8/99 Permit	
Great Plains Power, Weston Bend	MO	0.0036	Combustion Controls	11/01 Application	Recent application
Great Plains Power, Atchison Station	KS	0.0036	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
LG&E, Trimble County Generating Station	KY	0.0036	Combustion Controls	01/03 Application	Recent application
City Utilities of Springfield, Southwest Power Station	MO	0.0036	Combustion Controls	4/03 Application	Recent application
Municipal Energy Agency of Nebraska (Whelan Energy Center)	NE	0.0036	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Sandy Creek Energy Station	TX	0.0036	Combustion Controls	3/05 Draft Permit	Recent draft permit
Longleaf Energy Station	GA	0.0036	Combustion Controls	11/04 Application	Recent application
Otter Tail Power Company	SD	0.0036	Combustion Controls	4/06 Draft Permit	Recent draft permit

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Weston 4	WI	0.0036	Combustion Controls	7/7/06 RBLC	Recent permit
Comanche	CO	0.0035	Combustion Controls	7/05 Permit	Recent permit
Associated Electric Cooperative, Inc.	MO	0.0038	Combustion Controls	1/06 Application	Recent application
Duke Power – Cliffside	NC	0.004	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Palatka Generating Station (Seminole)	FL	0.004	Combustion Controls	3/06 EPA Ntl Coal Database Spreadsheet	Recent Application
Virginia Power (Dominion), Chesapeake	VA	0.004	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.6 lb/MMBtu
Longview Power	WV	0.004 (3-hr avg)	Combustion Controls	3/04 Permit (WV DEP website)	Recent permit
Prairie State Generating Station	IL	0.004	Combustion Controls	2/04 Permit (EPA reg. 5 website)	Recent draft permit
Wisconsin Electric, Elm Road Generating Station	WI	0.005	Combustion Controls	1/02 Application	Recent application

Table 10.79 - Lead Emissions Limits for PC-Fired Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Efficiency(%)	Control Technology	Source	Notes
Newmont Mining	NV	0.246×10^{-6}		Fabric Filter	11/04 Draft Permit	Recent draft permit
Thoroughbred Generating Station	KY	3.86×10^{-6} (quarterly avg.)			12/02 Permit (KY DEP website)	Recent permit
LG&E, Trimble County Generating Station	KY	3.96×10^{-6}			01/03 Application	Recent application
Keystone Cogeneration (Logan Energy)	NJ	4.7×10^{-6}		None	7/7/06 RBLC	
Kansas City Power & Light, Iatan Generating Station	MO	5.93×10^{-6}		Fabric Filter	1/06 Permit	Recent permit
City Public Service, Spruce Unit 2	TX	8.4×10^{-6} (annual avg.)		Fabric Filter	1/06 Permit	Recent permit
Sandy Creek Energy Station	TX	12×10^{-6}	99%	Fabric Filter	3/05 Draft Permit	Recent draft permit
Longleaf Energy Station	GA	12×10^{-6}	99%	Fabric Filter	11/04 Application	Recent application
Intermountain Power Project Unit 3	UT	16×10^{-6}		Fabric Filter	4/04 Draft Permit	Recent draft permit
Tucson Electric, Springerville Units 3 & 4	AZ	16×10^{-6}			2/02 Permit	Recent permit
Sunflower Electric Coop – Holcomb	KS	16.4×10^{-6}		Fabric Filter	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Great Plains Power, Weston Bend	MO	16.6×10^{-6}		Fabric Filter	11/01 Application	Recent application
Great Plains Power, Atchison Station	KS	16.6×10^{-6}		Fabric Filter	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Santee Cooper Cross Generating Station, Unit 3&4	SC	16.9×10^{-6}		ESP	3/06 EPA Ntl Coal Database Spreadsheet	Recent application

Facility	State	Emissions Limit (lb/MMBtu)	Control Efficiency(%)	Control Technology	Source	Notes
LG&E, Trimble County Generating Station	KY	18.1×10^{-6}		Fabric Filter	1/4/06 Permit (KY DEP website)	Recent permit
Sand Sage Power, Holcomb 2	KS	21.1×10^{-6}		Dry FGD and Fabric Filter	1/02 Permit	Recent permit
Duke Power – Cliffside	NC	22×10^{-6}		ESP + WESP	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Weston 4	WI	25×10^{-6}		Fabric Filter	7/7/06 RBLC	Recent Permit
Plum Point Energy Associates		26×10^{-6}		Fabric Filter	7/7/06 RBLC	Recent Permit
Kansas City Power & Light, Hawthorn Unit 5	MO	30×10^{-6}		Fabric Filter	8/99 Permit	
Desert Rock Energy Center	NM	200×10^{-6}		Fabric Filter	7/06 EPA Region 9 Permit	This entry included due to high level of interest in Desert Rock facility. This Pb limit is not among the most stringent.

Table 10.80 - Fluorine Emissions Limits for PC Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Species	Control Technology	Source	Notes
Longview Power	WV	1.0×10^{-5}	HF	Dry sorbent injection/Fabric Filter	3/04 Permit (WV DEP website)	Recent permit
Ware Cogen	MA	7.1×10^{-5}	F	Fabric Filter	7/7/06 RBLC	
Thoroughbred Generating Station	KY	1.6×10^{-4}	HF	FGD	12/02 Permit (KY DEP website)	Recent permit
Weston 4	WI	2×10^{-4}	F	Dry FGD, Baghouse	7/7/06 RBLC	Recent Permit
LG&E, Trimble County Generating Station	KY	2.2×10^{-4}	HF	WFGD	1/06 Permit (KY DEP website)	Recent permit
Desert Rock Energy Center	NM	2.4×10^{-4}	HF	Wet Scrubber	7/06 EPA Region 9 Permit	Will utilize unproven proprietary sorbent injection process/chemical.
Prairie State Generating Station	IL	2.6×10^{-4}	HF	Wet Scrubber/Wet ESP	2/04 Permit (EPA reg. 5 website)	Recent draft permit
Santee Cooper Cross Generating Station, Unit 3&4	SC	3.0×10^{-4}	HF	Wet Scrubber	02/04 Permit	BACT limit is also 112g MACT limit
Municipal Energy Agency of Nebraska (Whelan Energy Center)	NE	4.0×10^{-4}	HF	Dry Scrubber/ Fabric Filter	03/04 Permit	3-Hour Average
Plum Point Energy Station	AR	4.0×10^{-4}	HF/F	Dry Scrubber/ Fabric Filter	8/03 Permit	Recent permit
Rocky Mountain Power, Hardin	MT	4.0×10^{-4}		Dry Scrubber	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit modification
Omaha Public Power District	NE	4.0×10^{-4}	F	Dry Scrubber	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Comanche	CO	4.9×10^{-4}	HF	Dry Scrubber	7/05 Permit	Recent permit
Roanoke Valley Project	NC	5.4×10^{-4}	F	Dry Scrubber	7/7/06 RBLC	

Facility	State	Emissions Limit (lb/MMBtu)	Species	Control Technology	Source	Notes
Otter Tail Power Company	SD	6×10^{-4}	F	Wet Scrubber	4/06 Draft Permit	Recent draft permit
Sandy Creek Energy Station	TX	6.7×10^{-4}	HF	Dry Scrubber/ Fabric Filter	3/05 Draft Permit	Recent draft permit
Longleaf Energy Station	GA	6.7×10^{-4}	HF	Dry Scrubber/ Fabric Filter	11/04 Application	Recent application
Stone Container Corp.	LA	8.0×10^{-4}	F		7/7/06 RBLC	
City Public Service, Spruce Unit 2	TX	8.0×10^{-4} (annual avg.)	HF	Wet Scrubber/Fabric Filter	1/06 Permit	Recent permit
MidAmerican Energy, Council Bluffs	IA	9.0×10^{-4}	F	Dry Scrubber	4/03 Permit (IDNR website)	Recent permit
Plains Elect. Gen & Trans.	NM	1.0×10^{-3}	F		7/7/06 RBLC	
Keystone Cogeneration Systems	NJ	1.1×10^{-3}	HF		7/7/06 RBLC	
Nevada Power Co.	NV	1.6×10^{-3}	F	Wet Scrubber	7/7/06 RBLC	Never Built
SEI Birchwood	VA	1.6×10^{-3}	HF		7/7/06 RBLC	
Archer Daniels Midland Co.	IA	2.7×10^{-3}	F		7/7/06 RBLC	
Tennessee Eastman Company	TN	2.9×10^{-3}	F	Dry Scrubber	7/7/06 RBLC	
White Pine Power Project	NV	3.0×10^{-3}	F		7/7/06 RBLC	Never Built
Tennessee Eastman Company	TN	3.1×10^{-3}	F		7/7/06 RBLC	
Kansas City Power & Light, Iatan Generating Station	MO	4.3×10^{-3}	HF	Wet Scrubber	1/06 Permit	Recent permit
Reliant Energy, W A Parish Unit 8	TX	5.0×10^{-3}	HF	FGD/Fabric Filter	7/7/06 RBLC	

Facility	State	Emissions Limit (lb/MMBtu)	Species	Control Technology	Source	Notes
South Carolina Electric & Gas	SC	0.01	F	FGD/Fabric Filter	7/7/06 RBLC	

Table 10.81 - Most Stringent H_2SO_4 Emission Limits for PC Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Santee Cooper Cross Generating Station, Unit 3&4	SC	0.0014	Wet Scrubbing	02/04 Permit	PSD avoidance limit based on 365-day avg
Reliant Energy, W A Parish Unit 8	TX	0.0015	FGD/ Fabric Filter	7/7/06 RBLC	
Wisconsin Electric, Elm Road Generating Station	WI	0.0020	Fabric Filter	1/02 Application	Recent application
SEI Birchwood	VA	0.0022	Dry Scrubber	7/7/06 RBLC	1% S coal
Hadsen Power 13	VA	0.0022	Dry Scrubber	7/7/06 RBLC	1.3% S coal
Nevada Power Co.	NV	0.0023	Wet Scrubber	7/7/06 RBLC	Never Built
City Public Service, Spruce Unit 2	TX	0.0037 (annual avg.)	Wet Scrubber/Fabric Filter	1/06 Permit	Recent permit 1.2 lb/MMBtu S coal
Sandy Creek Energy Station	TX	0.0037 (annual avg.)	Dry Scrubber/ Fabric Filter	3/05 Draft Permit	Recent draft permit 1.2 lb/MMBtu S coal
LG&E Trimble County Generating Station	KY	0.0038 (3-hr avg.)	WESP	1/06 Permit (KY DEP website)	Recent permit
Associated Electric Cooperative, Inc.	MO	0.0038 (3-hr avg.)	Dry Scrubber/Baghouse	1/06 Application	Recent application
Desert Rock Energy Center	NM	0.0040 (3-hr avg.)	Wet Scrubber	7/06 EPA Region 9 Permit	Will utilize unproven proprietary sorbent injection process/chemical.
Comanche	CO	0.0042	Dry Scrubber	7/05 Permit	Recent permit
MidAmerican Energy, Council Bluffs	IA	0.0042	Dry Scrubber	4/03 Permit (IDNR website)	Recent permit
Omaha Public Power District	NE	0.0042	Dry Scrubber	3/06 EPA Ntl Coal Database Spreadsheet	Recent permit
Reliant Energy, W A Parish Units 5, 6 & 7	TX	0.0043		7/7/06 RBLC	
White Pine Power Project	NV	0.0045	Dry Scrubber	7/7/06 RBLC	Never Built

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Thoroughbred Generating Station	KY	0.00497	Wet Scrubber/ Wet ESP	12/02 Permit (KY DEP website)	Recent permit
Prairie State Energy Campus	IL	0.005	Wet Scrubber/ WESP	2/04 Permit (EPA reg. 5 website)	Draft permit
Longleaf Energy Station	GA	0.005	Dry Scrubber/ Fabric Filter	11/04 Application	Recent application
Otter Tail Power Company	SD	0.005	Wet Scrubber	4/06 Draft Permit	Recent draft permit
Weston 4	WI	0.005	Dry Scrubber/Fabric Filter	7/7/06 RBLC	Recent permit
Duke Power – Cliffside	NC	0.006	Wet Scrubber/WESP	3/06 EPA Ntl Coal Database Spreadsheet	Recent application
Plum Point Energy Station	AR	0.0061	Dry Scrubber/ Fabric Filter	8/03 Permit	Recent permit
Bull Mountain Development, Roundup Power	MT	0.0064	Dry Scrubber/ Fabric Filter	1/03 Permit	Recent permit
Kansas City Power & Light, Iatan Generating Station	MO	0.00716	Wet Scrubber	1/06 Permit	Recent permit

Table 10.82 – Most Stringent CO Emission Limits for Oil-Fired Auxiliary Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Sithe/Independence Power Partners	NY	0.02	Combustion Control	7/7/06 RBLC	NO_X emission rate is 0.2 lb/MMBtu
Fulton Cogeneration Associates	NY	0.035	Combustion Control	7/7/06 RBLC	NO_X emission rate is 0.14 lb/MMBtu
Neswc Resource Recovery Facility	MA	0.035	Combustion Control	7/7/06 RBLC	NO_X emission rate is 0.155 lb/MMBtu
Bull Mountain Development, Roundup Power	MT	0.035	Limit on Operating Hours to 200 hrs/yr	7/03 Permit	Recent permit; NO_X emission rate is 0.17 lb/MMBtu
Plum Point Energy Station	AR	0.036	Combustion Control	8/03 Permit	Recent permit; NO_X emission rate is 0.1 lb/MMBtu
Kes Chateaugay Project	NY	0.036		7/7/06 RBLC	NO_X emission rate is 0.2 lb/MMBtu
South Carolina Electric and Gas Company	SC	0.036		7/7/06 RBLC	NO_X emission rate is 0.17 lb/MMBtu
Indeck-Yerkes Energy Station	NY	0.038		7/7/06 RBLC	NO_X emission rate is 0.2 lb/MMBtu
Longleaf Energy Station	GA	0.04	Combustion Control	11/04 Application	Recent application
Power Authority of the State of NY	NY	0.041	Combustion Control	7/7/06 RBLC	
Indeck Silver Spring Cogeneration	NY	0.05		7/7/06 RBLC	
Black Hills Power and Light – Neil Simpson	WY	0.05		7/7/06 RBLC	
Thoroughbred Generating Station	KY	0.06		12/02 Permit (KY DEP website)	

Table 10.83 – Most Stringent NO_X Emission Limits for Oil-Fired Auxiliary Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Indeck Silver Spring Cogeneration	NY	0.041		7/7/06 RBLC	CO limit is 0.05 lb/MMBtu
River Hill Power Company, LLC	PA	0.09	LNB/FGR	7/7/06 RBLC	CO limit is 0.077 lb/MMBtu; not among the most stringent CO limits
Plum Point Energy Station	AR	0.1	LNB/FGR	8/03 Permit	Recent permit
Hopewell Cogeneration LP	VA	0.1	Boiler Design	7/7/06 RBLC	
AES Red Oak, LLC	NJ	0.1		7/7/06 RBLC	
Pilgrim Energy Center	NY	0.1		7/7/06 RBLC	
Longleaf Energy Station	GA	0.1	LNB/FGR	11/04 Application	Recent application
CPC International	CA	0.12	LNB, Staged Combustion	7/7/06 RBLC	
LSP – Cottage Grove, LP	MN	0.12	LNB/FGR	7/7/06 RBLC	
Doswell LP	VA	0.12	Burner Design	7/7/06 RBLC	
Thoroughbred Generating Station	KY	0.12		12/02 Permit (KY DEP website)	Recent permit

Table 10.84 - Most Stringent SO_2 Emission Limits for Oil-Fired Auxiliary Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Biomass Energy	OH	0.0125	Low sulfur fuel	7/7/06 RBLC	Recent permit
Piney Point Phosphates, Inc.	FL	0.05		7/7/06 RBLC	
Thoroughbred Generating Station	KY	0.051	Low sulfur fuel	12/02 Permit (KY DEP website)	Recent permit
AES Red Oak, LLC	NJ	0.051	Low sulfur fuel	7/7/06 RBLC	
Plum Point Energy Station	AR	0.051	Low sulfur fuel <.05% by wt.	8/03 Permit	Recent permit
Pine Bluff Energy Center	AR	0.052	Low sulfur fuel <0.05% by wt.	7/7/06 RBLC	
Longleaf Energy Station	GA	0.052	Low sulfur fuel <.05% by wt.	11/04 Application	Recent application
Bull Mountain Development, Roundup Power	MT	0.055	Low sulfur fuel <0.05% by wt.	7/03 Permit	Limit on Operating Hours (200 hrs/yr)
Gordonsville Energy	VA	0.06	Low sulfur fuel	7/7/06 RBLC	
Doswell Limited Partnership	VA	0.06	Low sulfur fuel	7/7/06 RBLC	
Kes Chateaugay Project	NY	0.08		7/7/06 RBLC	
Anitec Cogen Plant	NY	0.1	Low sulfur fuel <.1% by wt.	7/7/06 RBLC	
Black Hills Power and Light, Neil Simpson	WY	0.1		7/7/06 RBLC	
Old Dominion Electric Cooperative	VA	0.11	Low sulfur fuel	7/7/06 RBLC	

Table 10.85 – Most Stringent PM / PM_{10} Emission Limits for Oil-Fired Auxiliary Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
WGP, Inc.	ME	0.001	Clean burning fuel	7/7/06 RBLC	
Omaha Public Power District	NE	0.001	Sulfur Fuel Spec	7/7/06 RBLC	Recent permit
Pilgrim Energy Center	NY	0.005	Sulfur fuel spec.	7/7/06 RBLC	
Plum Point Energy Station	AR	0.0071	Low ash fuel	8/03 Permit	Recent permit
Anitec Cogen Plant	NY	0.01	Sulfur fuel spec.	7/7/06 RBLC	
Gordonsville Energy	VA	0.01	Clean burning fuel	7/7/06 RBLC	
Longleaf Energy Station	GA	0.011	Low ash fuel	11/04 Application	Recent application
Power Authority State of NY	NY	0.012		7/7/06 RBLC	
South Carolina Electric & Gas Company	SC	0.014	Low ash fuel oil spec.	7/7/06 RBLC	
Bull Mountain Development, Roundup Power	MT	0.014	Max. ash fuel of 0.25%	1/03 Permit	Recent permit
Fulton Cogeneration Associates	NY	0.014	Combustion Controls	7/7/06 RBLC	

Table 10.86 - Most Stringent VOC Emission Limits for Oil-Fired Auxiliary Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Plum Point Energy Station	AR	0.0015	Combustion Controls	8/03 Permit	Recent permit
Mead Containerboard	AL	0.0018		7/7/06 RBLC	NO_2 limit is 0.4 lb/MMBtu
WGP, Inc.	ME	0.002	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.22 lb/MMBtu
Appleton Paper, Inc.	WI	0.002		7/7/06 RBLC	
Pilgrim Energy Center	NY	0.003		7/7/06 RBLC	NO_X limit is 0.1 lb/MMBtu
Longleaf Energy Station	GA	0.003	Combustion Controls	11/04 Application	Recent application
Navy Public Works Center	VA	0.0041	Combustion Controls	7/7/06 RBLC	
AES Red Oak, LLC	NJ	0.005	Combustion Controls	7/7/06 RBLC	NO_X limit is 0.1 lb/MMBtu
River Hill Power Company, LLC	PA	0.005		7/7/06 RBLC	
Pine Bluff Energy Center	AR	0.005		7/7/06 RBLC	NO_X limit is 0.14 lb/MMBtu
Biomass Energy	OH	0.005		7/7/06 RBLC	NO_X limit is 0.19 lb/MMBtu
Lockport Cogen Facility	NY	0.005		7/7/06 RBLC	NO_X limit is 0.2 lb/MMBtu

Table 10.87 - H_2SO_4 Emission Limits for Oil-Fired Auxiliary Boilers

Facility	State	Emissions Limit (lb/MMBtu)	Control Technology	Source	Notes
Plum Point Energy Station	AR	0.0008	Low sulfur fuel	8/03 Permit	Recent permit
Longleaf Energy Station	GA	0.002	Low sulfur fuel	11/04 Application	Recent application
LSP – Cottage Grove, LP	MN	0.0025	Low sulfur fuel	7/7/06 RBLC	